Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(1)(a)1
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

A statement of the reason the adjustment is required.

Response:

KU's rates must be adjusted to a level which will provide it with an opportunity to recover sufficient revenues to operate its electric business successfully, maintain its financial integrity, attract capital and compensate investors for the risks assumed with respect to its electric business. KU is under earning. Its plant dedicated to the service of customers has increased since its last rate case. Despite ongoing and significant efforts to manage costs and the implementation of operational efficiencies, its operation and maintenance costs have increased. KU's current rates do not provide sufficient revenue to pay the expenses of its operations and also provide a fair and reasonable return on its capital. The rates presently charged by KU are no longer compensatory and are unfair, unjust and unreasonable. KU now seeks an increase in rates in order to provide it an opportunity to recover sufficient revenues to operate in a safe and reliable manner, maintain its financial integrity, and properly compensate its shareholders for the risks assumed with respect to jurisdictional operations. Please refer to the testimonies of Victor A. Staffieri, Paul W. Thompson, Chris Hermann, Kent W. Blake, Valerie L. Scott, Shannon L. Charnas, John J. Spanos, Daniel K. Arbough, William E. Avera, Lonnie E. Bellar, and Robert M. Conroy.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(1)(a)2
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

A statement that the utility's annual reports, including the annual report for the most recent calendar year, are on file with the Commission in accordance with 807 KAR 5:006, Section 3(1).

Response:

KU confirms that its annual reports, including the annual report for the most recent calendar year, are on file with the Commission in accordance with 807 KAR 5:006, Section 3(1).

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(1)(a)3
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

If the utility is incorporated, a certified copy of the utility's articles of incorporation and all amendments thereto or out-of-state documents of similar import. If the utility's articles of incorporation and amendments have already been filed with the commission in a prior proceeding, the application may state this fact making reference to the style and case number of the prior proceeding.

Response:

A certified copy of KU's Articles of Incorporation is already on file with the Commission in Case No. 2010-00204, *In the Matter of: Joint Application of PPL Corporation, E.ON AG, E.ON U.S. Investments Corp., E.ON U.S. LLC, Louisville and Gas Electric Company and Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities*, filed on May 28, 2010, and are incorporated by reference herein pursuant to 807 KAR 5:001, Section 8(3).

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(1)(a)4
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

If the utility is a limited partnership, a certified copy of the limited partnership agreement and all amendments thereto or out-of-state documents of similar import. If the utility's limited partnership agreement and amendments have already been filed with the commission in a prior proceeding, the application may state this fact making reference to the style and case number of the prior proceeding.

Response:

KU is not a limited partnership and, therefore, compliance with this filing requirement is not necessary.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(1)(a)5
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

If the utility is incorporated or is a limited partnership, a certificate of good standing or certificate of authorization dated within sixty (60) days of the date the application is filed.

Response:

See attached.

Commonwealth of Kentucky
Alison Lundergan Grimes, Secretary of State

Alison Lundergan Grimes
Secretary of State
P. O. Box 718
Frankfort, KY 40602-0718
(502) 564-3490
http://www.sos.ky.gov

Certificate of Existence

Authentication number: 125644
Visit https://app.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

I, Alison Lundergan Grimes, Secretary of State of the Commonwealth of Kentucky, do hereby certify that according to the records in the Office of the Secretary of State,

KENTUCKY UTILITIES COMPANY

is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is August 17, 1912 and whose period of duration is perpetual.

I further certify that all fees and penalties owed to the Secretary of State have been paid; that Articles of Dissolution have not been filed; and that the most recent annual report required by KRS 14A.6-010 has been delivered to the Secretary of State.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 9th day of May, 2012, in the 220th year of the Commonwealth.

COMMONWEALTH OF KENTUCKY
OFFICE OF SECRETARY OF STATE

Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
125644/0028494

Commonwealth of Virginia

State Corporation Commission

CERTIFICATE OF GOOD STANDING

I Certify the Following from the Records of the Commission:

That KENTUCKY UTILITIES COMPANY is duly incorporated under the law of the Commonwealth of Virginia;

That the date of its incorporation is November 26, 1991;

That the period of its duration is perpetual; and

That the corporation is in existence and in good standing in the Commonwealth of Virginia as of the date set forth below.

Nothing more is hereby certified.

Signed and Sealed at Richmond on this Date:
May 9, 2012

Joel H. Peck

Joel H. Peck, Clerk of the Commission

CISECOM
Document Control Number: 1205095616

STATE OF TENNESSEE
Tre Hargett, Secretary of State
Division of Business Services
William R. Snodgrass Tower
312 Rosa L. Parks AVE, 6th FL
Nashville, TN 37243-1102

CFS
STE B
992 DAVIDSON DR
NASHVILLE, TN 37205-1051

May 14, 2012

Request Type: Certificate of Existence/Authorization
Request #: 0066177

Issuance Date: 05/14/2012
Copies Requested: 1

Document Receipt

Receipt # : 755793 — Filing Fee: $20.00

Payment-Account - CFS, NASHVILLE, TN — $20.00

Regarding: KENTUCKY UTILITIES COMPANY

Filing Type:	Corporation For-Profit - Foreign	Control # :	38909
Formation/Qualification Date:	10/01/1919	Date Formed:	10/01/1919
Status:	Active	Formation Locale:	KENTUCKY
Duration Term:	Perpetual	Inactive Date:	

CERTIFICATE OF AUTHORIZATION

I, Tre Hargett, Secretary of State of the State of Tennessee, do hereby certify that effective as of the issuance date noted above

KENTUCKY UTILITIES COMPANY

* a Corporation formed in the jurisdiction set forth above, is authorized to transact business in this State;

* has paid all fees, taxes and penalties owed to this State (as reflected in the records of the Secretary of State and the Department of Revenue) which affect the existence/authorization of the business;

* has filed the most recent corporation annual report required with this office;

* has appointed a registered agent and registered office in this State;

* has not filed an Application for Certificate of Withdrawal.

Tre Hargett
Tre Hargett
Secretary of State

Processed By: Nichole Hambrick

Verification #: 000941823

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(1)(a)6
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that such a certificate is not necessary.

Response:

The legal name of KU is Kentucky Utilities Company. It has never done business in Kentucky under an assumed name and has never filed a Certificate of Assumed Name as may be required by KRS 365.015. KU does business in Virginia under the name Old Dominion Power Company. Please see the attached certificate regarding the use by KU of the name Old Dominion Power Company in Virginia. KU has never done business in Tennessee under an assumed name.

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Wise, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By John T. Newton
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of January, 1993.

George S. Brooks II
Notary Public

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Wise on the 26 day of November, 1991, and admitted to record as the law directs.

Terry L. Kilgore
Clerk

This is to certify that this is a true and correct reproduction or abstract of the official record filed with the Circuit Court for the City or County of Wise County/ City of Norton, Virginia.

C. Gary Rakes, Clerk

Date Issued 11-26-91

Terry L. Kilgore
~~Clerk~~ or Deputy

(SEAL)

VOID IF ALTERED OR DOES NOT BEAR IMPRESSED SEAL OF COURT

VS3A - 9/83

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Scott, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By [signature]
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of January, 1993.

NOTARY PUBLIC STATE AT LARGE, KY.

[signature]
Notary Public

COMMONWEALTH OF VIRGINIA:

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Scott on the 2nd day of December, 1991, and admitted to record as the law directs, at 8:00 A.M.

[signature]
Clerk

A TRUE COPY TESTE:
CIRCUIT COURT CLERK'S OFFICE
SCOTT COUNTY, VIRGINIA
[signature] CLERK

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Dickenson, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By John T. Newton
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of January, 1993.

George S. Brooks II
Notary Public

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Dickenson on the 26th day of November, 1991, and admitted to record as the law directs.

Lula Large, Deputy
Clerk

A COPY TESTE:

Lula Large DEPUTY CLERK

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Lee, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By John T. Newton
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of January, 1993.

NOTARY PUBLIC STATE AT LARGE

George S. Brooks II
Notary Public

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Lee on the 26th day of November, 1991, and admitted to record as the law directs.
1:28pm

Charles Calton Clerk
Clerk
By: Karen C. Jones DC

A COPY TESTE
CHARLES CALTON, CLERK
Karen C. Jones
Deputy Clerk

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Russell, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By John T. Newton
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of January, 1993.

George S. Brooks II
Notary Public

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Russell on the 26th day of November, 1991, and admitted to record as the law directs.

Perry Blevins
Clerk

A COPY TESTE
Joseph H. Gilmer, Clerk
Perry Blevins D. Clerk

Commonwealth of Virginia

State Corporation Commission

I Certify the Following from the Records of the Commission:

The foregoing is a true copy of the assumed or fictitious names filed in the Office of the Clerk by Kentucky Utilities Company on December 6, 1991.

Nothing more is hereby certified.

STATE CORPORATION COMMISSION
VIRGINIA
SIC SEMPER TYRANNIS
1903

Signed and Sealed at Richmond on this Date:
May 15, 2012

Joel H. Peck

Joel H. Peck, Clerk of the Commission

CIS0357

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Scott, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By John T. Newton
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of January, 1993.

NOTARY PUBLIC STATE AT LARGE, KY.

George S. Brooks II
Notary Public

COMMONWEALTH OF VIRGINIA:

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Scott on the 2nd day of December, 1991, and admitted to record as the law directs, at 8:00 A.M.

Harry G. Penley
Clerk

A TRUE COPY TESTE:
CIRCUIT COURT CLERK'S OFFICE
SCOTT COUNTY, VIRGINIA
Harry G. Penley, CLERK

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Dickenson, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By John T. Newton
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of January, 1993.

George S. Brooks II
Notary Public

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Dickenson on the 26th day of November, 1991, and admitted to record as the law directs.

Lula Large, Deputy
Clerk

A COPY TESTE:

Lula Large DEPUTY CLERK

Book 2 page 363

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Lee, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By John T. Newton
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of January, 1993.

NOTARY PUBLIC STATE AT LARGE

George S. Brooks II
Notary Public

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Lee on the 26th day of November, 1991, and admitted to record as the law directs.
1:28 pm

Charles Calton Clerk
Clerk
By: Karen C. Jones D.C.

A COPY TESTE
CHARLES CALTON, CLERK
Karen C. Jones
Deputy Clerk

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Russell, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By John T. Newton
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of January, 1993.

George S. Brooks II
Notary Public

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Russell on the 26th day of November, 1991, and admitted to record as the law directs.

Perry Blevins
Clerk

A COPY TESTE
Joseph H. Gilmer, Clerk
Perry Blevins D. Clerk

Commonwealth of Virginia

State Corporation Commission

I Certify the Following from the Records of the Commission:

The foregoing is a true copy of the assumed or fictitious names filed in the Office of the Clerk by Kentucky Utilities Company on December 6, 1991.

Nothing more is hereby certified.

Signed and Sealed at Richmond on this Date:
May 15, 2012

Joel H. Peck

Joel H. Peck, Clerk of the Commission

CIS0357

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(1)(a)7
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

The proposed tariff in a form which complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed.

Response:

See attached.

Kentucky Utilities Company

One Quality Street
Lexington, Kentucky

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

In seventy-seven counties in the Commonwealth of Kentucky
as depicted on territorial maps as filed with the

PUBLIC SERVICE COMMISSION

OF KENTUCKY

Date of Issue	Date Effective
June 29, 2012	August 1, 2012
	Subject to Article I.1.1 of the Settlement Agreement attached to and Approved in September 30, 2010 KPSC Order in Case No. 2010-00204

Issued by
Lonnie E. Bellar, Vice President
State Regulation and Rates

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

Date of Issue: **June 29, 2012**
Date Effective: **August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204**
Issued By: **Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky**

Standard Rate **RS**

RESIDENTIAL SERVICE

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available for single phase delivery to single family residential service subject to the terms and conditions on Sheet No. 100 of this Tariff. Three phase service under this rate schedule is restricted to those customers being billed on this rate schedule as of July 1, 2004.

RATE

Basic Service Charge:	$13.00 per month	I
Plus an Energy Charge of:	$ 0.07235 per kWh	I

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month’s charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: **June 29, 2012**
Date Effective: **August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204**
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Standard Rate **VFD**

VOLUNTEER FIRE DEPARTMENT SERVICE

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available for single-phase delivery, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load.

DEFINITION

To be eligible for this rate a volunteer fire department is defined as:

1) having at least 12 members and a chief,
2) having at least one firefighting apparatus, and
3) half the members must be volunteers

RATE

Basic Service Charge:	$13.00 per month	I
Plus an Energy Charge of:	$ 0.07235 per kWh	I

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month’s charges.

TERMS AND CONDITIONS

Service will be furnished under Company’s Terms and Conditions applicable hereto.

Date of Issue: **June 29, 2012**
Date Effective: **August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204**
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Standard Rate **GS**

GENERAL SERVICE RATE

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

To general lighting and small power loads for secondary service.

Service under this schedule will be limited to customers whose 12-month-average monthly maximum loads do not exceed 50 kW. Existing customers with 12-month-average maximum monthly loads exceeding 50 kW who are receiving service under P.S.C. 13, Fourth Revision of Original Sheet No. 10 as of February 6, 2009, will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer. T

RATE

Basic Service Charge:	$20.00 per month for single-phase service	I
	$35.00 per month for three-phase service	I
Plus an Energy Charge of:	$ 0.08678 per kWh	I

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD T

If Company determines based on Customer's usage history that Customer may be exceeding the maximum load permitted under Rate GS, Company may, at its discretion, equip Customer with a meter capable of measuring demand to determine Customer's continuing eligibility for Rate GS. If Customer is equipped with a demand-measuring meter, Customer's load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Standard Rate **AES**
ALL ELECTRIC SCHOOL

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rate is available for secondary and primary service to: T

(1) a complex of school buildings on a central campus,
(2) an individual school building, or
(3) an addition to an existing school building.

School buildings, as referred to herein, shall be defined as buildings used as classrooms, laboratories, gymnasiums, libraries, cafeterias, school related offices or for other bona fide school purposes by duly constituted school authorities of Kentucky. Served electrically by Kentucky Utilities Company, such energy requirements include, but are not limited to, lighting, heating, cooling, and water heating. School buildings not receiving every energy requirement electrically shall be separately metered from the above defined service and served under the applicable rate. Other fuels may be used as incidental to and for instructional laboratory and other miscellaneous purposes without affecting the availability of this rate.

At those locations where the school owns its distribution system and makes the service connections to the various buildings and/or load centers, Company shall be given the option of providing service by use of the existing Customer-owned distribution system, or of constructing its own facilities in accordance with the Company's Overhead Construction Standards. In any event, Company's investment in the facilities it provides may be limited to an amount not exceeding twice the estimated annual revenue from Customer's service. Should Company's investment in the facilities required to provide service to Customer exceed twice the revenue anticipated from the service to Customer and at Customer's option, Customer may make a contribution for the difference in the investment required in facilities necessary to provide service and twice the anticipated revenue, so as to receive service under this schedule. T T T

This Rate Schedule is not available to privately operated kindergartens or daycare centers and is restricted to those customers who were qualified for and being served on Rate AES as of July 1, 2011. Because this rate schedule is closed to new customers, if Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule.

RATE

Basic Service Charge:	$20.00 per meter per month for single-phase service	I
	$35.00 per meter per month for three-phase service	I
Plus an Energy Charge of:	$ 0.07060 per kWh	I

T

ADJUSTMENT CLAUSES T

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month's charges.

Standard Rate **PS**

POWER SERVICE

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rate schedule is available for secondary or primary service.

Service under this schedule will be limited to customers whose 12-month-average monthly minimum secondary loads exceed 50 kW and whose 12-month-average monthly maximum loads do not exceed 250 kW. Secondary or primary customers receiving service under PSC 13, Fourth Revision of Original Sheet No. 20, Large Power Service, or Fourth Revision of Original Sheet No. 30, Mine Power Service, as of February 6, 2009, with loads not meeting these criteria will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer. T T T T T T T

RATE

	Secondary	Primary	
Basic Service Charge per month:	$90.00	$125.00	I
Plus an Energy Charge per kWh of:	$ 0.03349	$ 0.03349	I
Plus a Demand Charge per kW of:			
Summer Rate:			
(Five Billing Periods of May through September)	$14.40	$ 14.75	I
Winter Rate:			
(All other months)	$12.10	$ 12.73	I

Where the monthly billing demand is the greater of:

a) the maximum measured load in the current billing period but not less than 50 kW for secondary service or 25 kW for primary service, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 60% of the contract capacity based on the maximum expected load on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Standard Rate

PS
POWER SERVICE

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed based on the measured kVA times 90 percent of the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD).

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured X 90\%}}{\text{Power Factor (in percent)}}$$

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Contracts under this rate shall be for an initial term of one (1) year, remaining in effect from month to month thereafter until terminated by notice of either party to the other.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: June 29, 2012
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Standard Rate **TODS**
TIME-OF-DAY SECONDARY SERVICE

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is available for secondary service. Service under this schedule will be limited to customers whose 12-month-average monthly minimum average loads exceed 250 kW and whose 12-month-average monthly maximum average loads do not exceed 5,000 kW. T T T

RATE

Basic Service Charge per month:	$200.00	
Plus an Energy Charge per kWh of:	$ 0.03590	I
Plus a Maximum Load Charge per kW of:		
Peak Demand Period	$ 4.50	I
Intermediate Demand Period	$ 2.80	I
Base Demand Period	$ 3.50	I

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
- a) the maximum measured load in the current billing period, or
- b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:
- a) the maximum measured load in the current billing period but not less than 250 kW, or
- b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
- c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

DETERMINATION OF MAXIMUM LOAD (continued)

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed based on the measured kVA times 90 percent, at the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD)

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured x 90\%}}{\text{Power Factor (in percent)}}$$

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Standard Rate **TODP**

TIME-OF-DAY PRIMARY SERVICE

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is available for primary service. Service under this schedule will be limited to customers whose 12-month-average monthly minimum average loads exceed 250 kVA and whose 12-month-average monthly maximum new loads do not exceed 50,000 kVA. Existing customers may increase loads to a 12-month-average monthly maximum of 75,000 kVA by up to 2,000 kVA per year or in greater increments with approval of Company's transmission operator. T

RATE

Basic Service Charge per month:	$300.00	
Plus an Energy Charge per kWh of:	$ 0.03557	I
Plus a Maximum Load Charge per kVA of:		
Peak Demand Period	$ 4.30	I
Intermediate Demand Period	$ 2.70	I
Base Demand Period	$ 1.60	I

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or

b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 250 kVA, or

b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or

c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Date of Issue: **June 29, 2012**

Date Effective: **August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204**

Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Standard Rate **TODP**

TIME-OF-DAY PRIMARY SERVICE

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party ninety (90) days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Standard Rate **RTS**

RETAIL TRANSMISSION SERVICE

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is available for transmission service. Service under this schedule will be limited to customers whose 12-month-average monthly maximum new loads do not exceed 50,000 kVA. Existing customers may increase loads to a 12-month-average monthly maximum of 75,000 kVA by up to 2,000 kVA per year or in greater increments with approval of Company's transmission operator. T

RATE

Basic Service Charge per month:	$750.00	I
Plus an Energy Charge per kWh of:	$ 0.03408	R
Plus a Maximum Load Charge per kVA of:		
Peak Demand Period	$ 3.90	I
Intermediate Demand Period	$ 2.90	I
Base Demand Period	$ 1.30	I

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Standard Rate **RTS**

RETAIL TRANSMISSION SERVICE

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year and for yearly periods thereafter until terminated by either party giving written notice to the other party ninety (90) days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: **June 29, 2012**
Date Effective: **August 1, 2010**
Issued By: **Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky**

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Standard Rate **FLS**

Fluctuating Load Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available for primary or transmission service to customers up to an aggregate of two hundred (200) MVA for all customers taking service under this schedule and under the Fluctuating Load Service Rate FLS schedule of Louisville Gas and Electric Company. This schedule is restricted to individual customers whose monthly demand is twenty (20) MVA or greater. A customer is defined as a fluctuating load if that customer's load either increases or decreases twenty (20) MVA or more per minute or seventy (70) MVA or more in ten (10) minutes when such increases or decreases exceed one (1) occurrence per hour during any hour of the billing month.

Subject to the above aggregate limit of two hundred (200) MVA, this schedule is mandatory for all customers whose load is defined as fluctuating and not served on another standard rate schedule as of July 1, 2004.

BASE RATE

	Primary	Transmission	
Basic Service Charge per month:	$750.00	$750.00	I
Plus an Energy Charge per kWh of:	$ 0.03419	$ 0.03092	I
Plus a Maximum Load Charge per kVA of:			
Peak Demand Period	$ 2.40	$ 2.40	I
Intermediate Demand Period	$ 1.44	$ 1.44	I
Base Demand Period	$ 1.75	$ 1.00	I

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of: T

a) the maximum measured load in the current billing period, or T
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of: T

a) the maximum measured load in the current billing period but not less than 20,000 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

T

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Date Effective: **August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204**
Issued By: **Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky**

T

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD
The load will be measured and will be the average kVA demand delivered to the customer during the 5-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS
The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges. T T T

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TERM OF CONTRACT

Unless terminated by mutual agreement, the initial term of contract for service shall be for a fixed term of five years with successive one year term renewal until canceled by either party giving at least one (1) year written notice to the other prior to the end of the initial term or the then current annual renewal period, as applicable.

PROTECTION OF SERVICE

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other undesirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 14(1)(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other T guarantees. Company shall be held harmless for any damages or economic loss resulting from such termination of service. If requested by Company, Customer shall provide all available information to Company that aids Company in enforcing its service standards. If Company at any time has a reasonable basis for believing that Customer's proposed or existing use of the service provided will not comply with the service standards for interference, fluctuations, or harmonics, Company may engage such experts and/or consultants as Company shall determine are appropriate to advise Company in ensuring that such interference, fluctuations, or harmonics are within acceptable standards. Should such experts and/or consultants determine Customer's use of service is unacceptable, Company's use of such experts and/or consultants will be at the Customer's expense.

SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA

Company reserves the right to interrupt up to 95% of Customer's load to facilitate Company compliance with system contingencies and with industry performance criteria. Customer will permit Company to install electronic equipment and associated real-time metering to permit Company interruption of Customer's load. Such equipment will immediately notify Customer five (5) minutes before an electronically initiated interruption that will begin immediately thereafter and last no longer than ten (10) minutes nor shall the interruptions exceed twenty (20) per month. Such interruptions will not be accumulated nor credited against annual hours, if any, under the CURTAILABLE SERVICE RIDERS CSR10 AND CSR 30. Company's right to

Interrupt under this provision is restricted to responses to unplanned outage or de-rates of LG&E and KU Energy LLC System (LKE System) owned or purchased generation or when Automatic Reserve Sharing is invoked. LKE System, as used herein, shall consist of KU and LG&E. At customer's request, Company shall provide documentation of the need for interruption under this provision within sixty (60) days of the end of the applicable billing period. T

LIABILITY

In no event shall Company have any liability to the Customer or any other party affected by the electrical service to the Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to the Customer or any other party. In the event that the Customer's use of Company's service causes damage to Company's property or injuries to persons, the Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Standard Rate **LS** N

Lighting Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rate schedule is offered, under the conditions set out hereinafter, for lighting applications such as, but not limited to, the illumination of street, driveways, yards, lots, and other outdoor areas where secondary voltage of 120/240 is available.

Service will be provided under written contract, signed by customer prior to service commencing, when additional facilities are required.

Units marked with an asterisk (*) are not available for use in residential neighborhoods except by municipal authorities.

OVERHEAD SERVICE

Based on Customer's lighting choice, Company will furnish, own, install, and maintain the lighting unit. A basic overhead service includes lamp, fixture, photoelectric control, mast arm, and, if needed, up to 150 feet of conductor per fixture on existing wood poles (fixture only). Company will, upon request, furnish ornamental poles of Company's choosing, together with overhead wiring and all other equipment mentioned for basic overhead service.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge	
				Fixture Only	Ornamental
High Pressure Sodium					
462/472	Cobra Head	5,800	0.083	$ 8.33	$11.32
463/473	Cobra Head	9,500	0.117	8.87	12.08
464/474	Cobra Head	22,000*	0.242	13.75	16.96
465/475	Cobra Head	50,000*	0.471	22.10	23.74
487	Directional	9,500	0.117	$ 8.72	
488	Directional	22,000*	0.242	13.13	
489	Directional	50,000*	0.471	18.67	
428	Open Bottom	9,500	0.117	$ 7.55	
Metal Halide					
450	Directional	12,000*	0.150	$13.75	
451	Directional	32,000*	0.350	19.46	
452	Directional	107,800*	1.080	40.58	

OVERHEAD SERVICE (continued)

Should Customer request underground service, Customer shall make a non-refundable cash contribution prior to the time of installation, or, at the option of company, make a work contribution to Company for the difference in the installed cost of the system requested and the cost of the overhead lighting system.

Where the location of existing poles is not suitable or where there are no existing poles for mounting of lights, and Customer requests service under these conditions, Company may furnish the requested facilities at an additional charge to be determined under the Excess Facilities Rider.

UNDERGROUND SERVICE

Based on Customer's lighting choice, Company will furnish, own, install, and maintain poles, fixtures, and any necessary circuitry up to 200 feet. All poles and fixtures furnished by Company will be standard stocked materials. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for underground installation.

RATE

				Monthly Charge		
Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Fixture Only**	**Decorative Smooth**	**Historic Fluted**
High Pressure Sodium						
467	Colonial	5,800	0.083		$10.47	
468	Colonial	9,500	0.117		10.92	
401/411	Acorn	5,800	0.083		$14.62	$21.24
420/430	Acorn	9,500	0.117		15.18	21.92
414	Victorian	5,800	0.083			$30.84
415	Victorian	9,500	0.117			31.27
492/476	Contemporary	5,800	0.083	$15.13	$16.58	
497/477	Contemporary	9,500	0.117	15.17	20.87	
498/478	Contemporary	22,000*	0.242	17.27	26.55	
499/479	Contemporary	50,000*	0.471	20.72	32.54	
300	Dark Sky Lantern	4,000	0.060		$22.48	
301	Dark Sky Lantern	9,500	0.117		23.44	

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Decorative Smooth	Historic Fluted
360	Granville	16,000	0.181		$53.79	

Granville Accessories:	
Twin Crossarm Bracket (includes 1 fixture)	$20.87
24 Inch Banner Arm	3.26
24 Inch Clamp Banner Arm	4.49
18 Inch Banner Arm	3.00
18 Inch Clamp Banner Arm	3.71
Flagpole Holder	1.38
Post-Mounted Receptacle	19.47
Additional Post-Mounted Receptacle (Limit 1 Per Pole)	2.66
Planter	4.51
Clamp-On Planter	5.01

Granville units are restricted to installations and configurations for the cities of Lexington and London

Metal Halide

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Fixture Only	Decorative Smooth	Historic Fluted
490/494	Contemporary	12,000*	0.150	$14.99	$28.08	
491/495	Contemporary	32,000*	0.350	21.22	34.31	
493/496	Contemporary	107,800*	1.080	43.98	57.07	

Customer shall make a non-refundable cash contribution prior to the time of installation, or, at the option of Company, make a work contribution to Company for the difference in the installed cost of the system requested and the cost of the conventional overhead lighting system.

Where Customer's location would require the installation of additional facilities, Company may furnish, own, and maintain the requested facilities at an additional charge per month to be determined under the Excess Facilities Rider.

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill. Billing for this service to be made a part of bill rendered for other electric service.

DETERMINATION OF ENERGY CONSUMPTION

The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice to the other when additional facilities are required. Cancellation by Customer prior to the initial five-year term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the original five (5) year term.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.

2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults. Company shall initiate service corrections within two (2) business days after such notification by Customer.

3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.

4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.

5. If any permit is required from any municipal or other governmental authority with respect to installation and use of any of the lighting units provided hereunder, Company will seek such permits, but the ultimate responsibility belongs with Customer

6. If Customer requests the removal of an existing lighting system, including, but not limited to, fixtures, poles, or other supporting facilities that were in service less than twenty years, and requests installation of replacement lighting within 5 years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.

7. Temporary suspension of lighting service is not permitted. Upon permanent discontinuance of service, lighting units and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

Standard Rate **RLS** N

Restricted Lighting Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rate schedule is restricted to those lighting fixtures/poles in service as of August 1, 2012, except where a spot replacement maintains the continuity of multiple fixtures/poles comprising a neighborhood lighting system. Spot placement of restricted fixtures/poles is contingent on the restricted fixtures/poles being available from manufacturers. Spot replacement of restricted units will be made under the terms and conditions provided for under non-restricted Lighting Service Rate LS.

In the event restricted fixtures/poles fail and replacements are unavailable, Customer will be given the choice of having Company remove the failed fixture/pole or replacing the failed fixture/pole with other available fixture/pole.

OVERHEAD SERVICE

Based on Customer's lighting choice, Company has furnished, installed, and maintained the lighting unit complete with lamp, fixture, photoelectric control, mast arm, and, if needed, up to 150 feet of conductor per fixture on existing wood poles (fixture only). Company has, upon request, furnished poles, of Company's choosing, together with overhead wiring and all other equipment mentioned for overhead service.

RATE

				Monthly Charge	
Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Fixture Only**	**Fixture and Pole**
High Pressure Sodium					
461/471	Cobra Head	4,000	0.060	$ 7.31	$10.29
409	Cobra Head	50,000	0.471	10.81	
426	Open Bottom	5,800	0.083	7.09	
Metal Halide					
454	Directional	12,000	0.150		$18.21
455	Directional	32,000	0.350		23.92
459	Directional	107,800	1.080		45.05
Mercury Vapor					
446/456	Cobra Head	7,000	0.207	$ 9.20	$11.54
447/457	Cobra Head	10,000	0.294	10.85	12.93
448/458	Cobra Head	20,000	0.453	12.19	14.49
404	Open Bottom	7,000	0.207	10.22	
Incandescent					
421	Tear Drop	1,000	0.102	$ 3.25	
422	Tear Drop	2,500	0.201	4.31	
424/434	Tear Drop	4,000	0.327	6.41	$ 7.38
425	Tear Drop	6,000	0.447	8.55	

OVERHEAD SERVICE (continued)

Where the location of existing poles was not suitable, or where there were no existing poles for mounting of lights, and Customer requested service under these conditions, Company may have furnished the requested facilities at an additional charge determined under the Excess Facilities Rider.

UNDERGROUND SERVICE

Based on Customer's lighting choice, Company has furnished, installed, and maintained the lighting unit complete with lamp, fixture, photoelectric control, mast arm, and, if needed, up to 200 feet of conductor per fixture on appropriate poles.

RATE

				Monthly Charge		
Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Wood Pole**	**Decorative Smooth**	**Historic Fluted**
Metal Halide						
460	Directional	12,000	0.150		$26.84	
469	Directional	32,000	0.350		32.55	
470	Directional	107,800	1.080		53.67	
High Pressure Sodium						
440/410	Acorn	4,000	0.060		$13.47	$20.21
466	Colonial	4,000	0.060		$ 9.42	
412	Coach	5,800	0.083		$30.84	
413	Coach	9,500	0.117		31.27	

DUE DATE OF BILL

Payment is due within twelve (12) calendar days from the date of the bill. Billing for this service to be made a part of the bill rendered for other electric service.

DETERMINATION OF ENERGY CONSUMPTION

The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice to the other when additional facilities are required. Cancellation by Customer prior to the initial five-year term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the original five (5) year term.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.

2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults, and the Company shall initiate service corrections within two (2) business days after such notification by Customer.

3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.

4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.

5. Temporary suspension of lighting service is not permitted. Upon permanent discontinuance of service, lighting units and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

Standard Rate **LE**
Lighting Energy Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to municipalities, county governments, divisions or agencies of the state or Federal governments, civic associations, and other public or quasi-public agencies for service to public street and highway lighting systems, where the municipality or other agency owns and maintains all street lighting equipment and other facilities on its side of the point of delivery of the energy supplied hereunder.

RATE

$0.05958 per kWh I

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

CONDITIONS OF DELIVERY
a) Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption taking into account the types of equipment served.

b) The location of the point of delivery of the energy supplied hereunder and the voltage at which such delivery is effected shall be mutually agreed upon by Company and the customer in consideration of the type and size of customer's street lighting system and the voltage which Company has available for delivery.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Standard Rate **TE**
Traffic Energy Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to municipalities, county governments, divisions of the state or Federal governments or any other governmental agency for service on a 24-hour all-day every-day basis, where the governmental agency owns and maintains all equipment on its side of the point of delivery of the energy supplied hereunder. In the application of this rate each point of delivery will be considered as a separate customer.

This service is limited to traffic control devices including, signals, cameras, or other traffic lights and electronic communication devices.

RATE

Basic Service Charge:	$3.25 per delivery per month	I
Plus an Energy Charge of:	$0.07614 per kWh	I

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

CONDITIONS OF SERVICE
1. Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption, taking into account the size and characteristics of the load, or on meter readings obtained from a similar installation.

2. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and the customer. Where attachment of Customer’s devices is made to Company facilities, Customer must have an attachment agreement with Company.

3. Loads not operated on an all-day every-day basis will be served under the appropriate rate.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: **June 29, 2012**
Date Effective: **August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204**
Issued By: **Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky**

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Where Company is willing to permit the attachments of cables, wires and appliances to its poles where, in Company's judgment, such attachments will not interfere with its electric service requirements and other prior licensees using Company's poles. Attachments will be permitted upon execution by both parties of a Cable Television Attachment Agreement supplied by Company.

ATTACHMENT CHARGE
$10.01 per year for each attachment to pole. I

BILLING
Attachment Charges to be billed semi-annually based on the number of pole attachments being maintained on December 1 and June 1. Provided, however, that should the Agreement be terminated in accordance with the terms of the said Agreement, the Attachment Charges will be prorated to the date of such termination. Payment will be due within thirty (30) days from date of bill. Non-payment of bills shall constitute a default of the Agreement.

TERM OF AGREEMENT
The Cable Television Attachment Agreement shall become effective upon execution by both parties and shall continue in effect for not less than one (1) year, subject to provisions contained in the agreement. At any time thereafter, the Customer may terminate the agreement by giving not less than six (6) months' prior written notice. Upon termination of the agreement, Customer shall immediately remove its cables, wire, appliances and all other attachments from all poles of Company.

TERMS AND CONDITIONS OF POLE ATTACHMENTS
Pole attachments shall be permitted in accordance with this Schedule. Company's Terms and Conditions shall be applicable, to the extent they are not in conflict with or inconsistent with, the special provisions of this Schedule.

Upon written Agreement, Company is willing to permit, to the extent it may lawfully do so, the attachment of cables, wires and appliances to its poles by a cable television system operator, hereinafter "Customer," where, in its judgment, such use will not interfere with its electric service requirements and other prior licensees using Company's poles, including consideration of economy and safety, in accordance with this schedule approved by the Public Service Commission. The Terms and Conditions applicable to such service are as follows:

Standard Rate **CTAC**
Cable Television Attachment Charges

1. **ATTACHMENT APPLICATIONS AND PERMITS**
   Before making attachment to any pole or poles of Company, Customer shall make application and receive a permit therefore on a form to be supplied by Company. The information submitted by Customer with the application for a permit shall consist of drawings and associated descriptive matter which shall be adequate in all detail to enable Company to thoroughly check the proposed installation of Customer. Before the attachments are made, the permit must be approved by Company. Customer shall not build separate pole lines along existing facilities of Company and shall not place intermediate poles in spans of Company, unless authorized by Company in writing. Company shall have the right to remove unauthorized Customer attachments at Customer's expense after notice to Customer. In the event a pole attachment count does not correspond to the recorded attachment count, Customer will pay a back attachment fee for any excess attachments. The back attachment fee will be double the rate otherwise in effect over the time since last pole attachment count and shall be payable on demand.

2. **PERMITTED ATTACHMENTS**
   Customer shall be permitted to make only one bolt attachment for one messenger on tangent poles and two bolt attachments for two messengers on corner poles. A maximum of five individual coaxial cables may be supported by any single messenger if these cables are all attached to the messenger by suitable lashings or bindings, and so that the maximum overall dimension of the resulting cable bundle does not exceed two (2) inches. Any messenger attachment other than to tangent poles must be properly braced with guys and anchors provided by Customer to the satisfaction of Company. The use of existing Company anchors for this purpose must be specifically authorized in writing, subject to additional charge, and will not ordinarily be permitted. The use of crossarms or brackets shall not be permitted. In addition to messenger attachments, Customer will be permitted one Customer amplifier installation per pole and four service drops to be tapped on cable messenger strand and not on pole. Customer power supply installations shall be permitted, but only at pole locations specifically approved by Company. Any or all of the above are considered one attachment for billing purposes. Any additional attachments desired by Customer will be considered on an individual basis by Company, and as a separate attachment application.

3. **CONSTRUCTION AND MAINTENANCE REQUIREMENTS AND SPECIFICATIONS**
   Customer's cables, wires and appliances, in each and every location, shall be erected and maintained in accordance with the requirements and specifications of the National Electrical Safety Code, current edition, and Company's construction practices, or any amendments or revisions of said Code and in compliance with any rules or orders now in effect or that hereinafter may be issued by the Public Service Commission of Kentucky, or other authority having jurisdiction. In the event any of Customer's construction does not meet any of the foregoing requirements, Customer will correct same in fifteen work days after written notification. Company may make corrections and bill Customer for total costs incurred, if not corrected by Customer.

4. **MAINTENANCE OF ATTACHMENTS**
   Customer shall, at its own expense, make and maintain said attachments in safe condition and in thorough repair, and in a manner suitable to Company and so as not to conflict with the use of said poles by Company, or by other parties, firms, corporations, governmental units, etc., using said poles, pursuant to any license or permit by Company, or interfere with the working

use of facilities thereon or which may, from time to time, be placed thereon. Customer shall promptly at any time, at its own expense, upon written notice from Company, relocate, replace or renew its facilities placed on said poles, and transfer them to substituted poles, or perform any other work in connection with said facilities that may be required by Company but in no case longer than 30 day after date of written request. In cases of emergency, however, Company may arrange to relocate, replace or renew the facilities placed on said poles by Customer, transfer them to substituted poles or perform any other work in connection with said facilities that may be required in the maintenance, replacement, removal or relocation of said poles, the facilities thereon or which may be placed thereon, or for the service needs of Company, or its other licensees, and Customer shall, on demand, reimburse Company for the expense thereby incurred.

5. COSTS ASSOCIATED WITH ATTACHMENTS

In the event that any pole or poles of Company to which Customer desires to make attachments are inadequate to support the additional facilities in accordance with the aforesaid specifications, Company will indicate on the application and permit form the changes necessary to provide adequate poles and the estimated cost thereof to Customer. If Customer still desires to make the attachments, Company will replace such inadequate poles with suitable poles and Customer will, on demand, reimburse Company for the total cost of pole replacement necessary to accommodate Customer attachments, less the salvage value of any pole that is removed, and the expense of transferring Company's facilities from the old to the new poles. Where Customer desired attachments can be accommodated on present poles of Company by rearranging Company's facilities thereon, Customer will compensate Company for the full expense incurred in completing such rearrangements, within ten days after receipt of Company's invoice for such expense. Customer will also, on demand, reimburse the owner or owners of other facilities attached to said poles for any expense incurred by it or them in transferring or rearranging said facilities. In the event Customer makes an unauthorized attachment which necessitates rearrangements when discovered, then Customer shall pay on demand twice the expense incurred in completing such rearrangements.

6. MAINTENANCE AND OPERATION OF COMPANY'S FACILITIES

Company reserves to itself, its successors and assigns, the right to maintain its poles and to operate its facilities thereon in such manner as will, in its own judgment, best enable it to fulfill its electric service requirements, but in accordance with the specifications herein before referred to. Company shall not be liable to Customer for any interruption to service to Customer's subscribers or for interference with the operation of the cables, wires and appliances of Customer arising in any manner out of the use of Company's poles hereunder.

7. FRANCHISES AND EASEMENTS

Customer shall submit to Company evidence, satisfactory to Company, of Customer's authority to erect and maintain Customer's facilities within public streets, highways and other thoroughfares within the above described territory which is to be served and shall secure any necessary consent by way of franchise or other satisfactory license, permit or authority, acceptable to Company from State, County or municipal authorities or from the owners of property where necessary to construct and maintain facilities at the locations of poles of Company which it desires to use. Customer must secure its own easement rights on private property. Customer must, regardless of authority received or franchises given by governmental agencies, conform to all requirements of Terms and Conditions with regard to Company's property. Company's approval of attachments shall not constitute any representation or warranty by Company to Customer regarding Customer's right to occupy or use any public or private right-of-way.

8. INSPECTION OF FACILITIES
Company reserves the right to inspect each new installation of Customer on its poles and in the vicinity of its lines or appliances and to make periodic inspections, every two (2) years or more often as plant conditions warrant of the entire plant of Customer. Such inspections, made or not, shall not operate to relieve Customer of any responsibility, obligation or liability.

9. PRECAUTIONS TO AVOID FACILITY DAMAGE
Customer shall exercise precautions to avoid damage to facilities of Company and of others supported on said poles; and shall assume all responsibility of any and all loss for such damage caused by it. Customer shall make an immediate report to Company of the occurrence of any damage and shall reimburse Company for the expense incurred in making repairs.

10. INDEMNITIES AND INSURANCE
Customer shall defend, indemnify and save harmless Company from any and all damage, loss, claim, demand, suit, liability, penalty or forfeiture of every kind and nature-including but not limited to costs and expenses of defending against the same and payment of any settlement or judgment therefore, by reason of (a) injuries or deaths to persons, (b) damages to or destructions of properties, (c) pollutions, contaminations of or other adverse effects on the environment or (d) violations of governmental laws, regulations or orders whether suffered directly by Company it-self or indirectly by reason of claims, demands or suits against it by third parties, resulting or alleged to have resulted from acts or omissions of Customer, its employees, agents, or other representatives or from their presence on the premises of Company, either solely or in concurrence with any alleged joint negligence of Company.

Customer shall provide and maintain in an Insurance Company(s) authorized to do business in the Commonwealth of Kentucky, the following:

(a) Insurance protection for Customer employees to the extent required by the Workmen's Compensation Law of Kentucky and, where same is not applicable or if necessary to provide a defense for Company, Employer's Liability Protection (covering both Company and Customer) for Customer employees for no less than $100,000.00 per employee.

(b) Public Liability and Business Liability insurance with a minimum limit of $500,000.00 for each person injured and with a minimum total limit of $1,000,000.00 for each accident and a minimum limit of $100,000.00 for property damage for each accident.

(c) Public Liability and Property Damage insurance on all automotive equipment used by Customer on job to the extent of the amounts for Public Liability and Property Damage insurance set out in the preceding Paragraph (b).

(d) In the event that work covered by the Agreement includes work to be done in places or areas where the Maritime Laws are in effect, then and in that event additional insurance protection to the limits in Paragraph (b) above for liability arising out of said Maritime Laws.

(e) In the event the work covers fixed wing aircraft, rotor lift, lighter than air aircraft or any other form of aircraft, appropriate insurance will be carried affording protection to the limits prescribed in the preceding Paragraph (b).

(f) In the event the work covers blasting, explosives or operations underground, in trenches or other excavations, appropriate insurance will be carried affording protection to the limits prescribed in the preceding Paragraph (b), together with products hazard and completed operations insurance where applicable, affording protection to the limits above prescribed. Customer's liability insurance shall be written to eliminate XCU exclusions. Said insurance is to be kept in force for not less than one year after cancellation of the Agreement.

Before starting work, Customer shall furnish to Company a certificate(s) of insurance satisfactory to Company, evidencing the existence of the insurance required by the above provisions, and this insurance may not be canceled for any cause without sixty (60) days advance written notice being first given Company; provided, that failure of Company to require Customer to furnish any such certificate(s) shall not constitute a waiver by Company of Customer's obligation to maintain insurance as provided herein.

Each policy required hereunder shall contain a contractual endorsement written as follows: "The insurance provided herein shall also be for the benefit of Kentucky Utilities Company so as to guarantee, within the policy limits, the performance by the named insured of the indemnity provisions of the Cable Television Attachment Agreement between the named insured and Kentucky Utilities Company. This insurance may not be canceled for any cause without sixty (60) days advance written notice being first given to Kentucky Utilities Company."

11. ATTACHMENT REMOVAL AND NOTICES

Customer may at any time voluntarily remove its attachments from any pole or poles of Company, but shall immediately give Company written notice of such removal on a form to be supplied by Company. No refund of any attachment charge will be due on account of such voluntary removal.

12. FORBIDDEN USE OF POLES

Prior to Customer's initial attachment, Company reserves the right due to engineering design requirements to refuse use by Customer of certain or specific poles or structures (such as normal transmission routes). Upon notice from Company to Customer that the use of any pole or poles is forbidden by municipal or other public authorities or by property owners, the permit covering the use of such pole or poles shall immediately terminate and Customer shall remove its facilities from the affected pole or poles at once. No refund of any attachment charge will be due on account of any removal resulting from such forbidden use.

13. NON-COMPLIANCE

If Customer shall fail to comply with any of the provisions of these Rules and Regulations or Terms and Conditions or default in any of its obligations under these Rules and Regulations or Terms and Conditions and shall fail within thirty (30) days after written notice from Company to correct such default or non-compliance, Company may, at its option, forthwith terminate the Agreement or the permit covering the poles as to which such default or non-compliance shall have occurred, by giving written notice to Customer of said termination. No refund of any rental will be due on account of such termination.

14. **WAIVERS**
Failure to enforce or insist upon compliance with any of these Rules and Regulations or Terms and Conditions or the Agreement shall not constitute a general waiver or relinquishment thereof, but the same shall be and remain at all times in full force and effect.

15. **USE OF COMPANY'S FACILITIES BY OTHERS**
Nothing herein contained shall be construed as affecting the rights or privileges previously conferred by Company, by contract or otherwise, to others, not parties to the Agreement, to use any poles covered by the Agreement; and Company shall have the right to continue and to extend such rights or privileges. The attachment privileges herein granted shall at all times be subject to such existing contracts and arrangements.

16. **ASSIGNMENT**
Customer shall not assign, transfer or sublet the privileges hereby granted and/or provided in the Agreement without the prior consent in writing of Company.

17. **PROPERTY RIGHTS**
No use, however extended, of Company poles under the Agreement shall create or vest in Customer any ownership or property rights in said poles, but Customer shall be and remain a customer only. Nothing herein contained shall be construed to compel Company to maintain any of said poles for a period longer than demanded by its electric service requirements.

18. **FAILURE TO PROCEED**
Customer agrees to proceed as expeditiously as practical with the work of providing the television cable service to the area described in the Agreement. Within ninety (90) days from the date of the Agreement, Customer shall make progress reasonably satisfactory to Company in the installation of its facilities or shall demonstrate, to the reasonable satisfaction of Company, its ability to proceed expeditiously.

19. **TERMINATION**
Upon termination of the Agreement in accordance with any of its terms, Customer shall immediately remove its cables, wires and appliances from all poles of Company. If not removed, Company shall have the right to remove them at the cost and expense of Customer.

20. **SECURITY**
Customer shall furnish bond for the purposes hereinafter specified as follows:

(a) during the period of Customer's initial installation of its facilities and at the time of any expansion involving more than seventy-five (75) poles, a bond in the amount of $2,000 for each 100 poles (or fraction thereof) to which Customer intends to attach its facilities;
(b) following the satisfactory completion of Customer's initial installation, the amount of bond shall be reduced to $1,000 for each 100 poles (or fraction thereof);
(c) after Customer has been a customer of Company pursuant to the Agreement and is not in default thereunder for a period of three years, the bond shall be reduced to $500 for each 100 poles (or fraction thereof).

(d) such bond shall contain the provision that it shall not be terminated prior to six (6) months' after receipt by Company of written notice of the desire of the bonding or insurance company to terminate such bond. This six (6) months' termination clause may be waived by Company if an acceptable replacement bond is received before the six (6) months has ended. Upon receipt of such termination notice, Company shall request Customer to immediately remove its cables, wires and all other facilities from all poles of Company. If Customer should fail to complete the removal of all of its facilities from the poles of Company within thirty (30) days after receipt of such request from Company, then Company shall have the right to remove them at the cost and expense of Customer and without being liable for any damage to Customer's wires, cables, fixtures or appurtenances. Such bond shall guarantee the payment of any sums which may become due to Company for rentals, inspections or work performed for the benefit of Customer under the Agreement, including the removal of attachments upon termination of the Agreement by any of its provisions.

(e) Company in its sole discretion may agree in writing to accept other collateral (such as a cash deposit or an irrevocable bank letter of credit) in substitution for the bond required by, and subject to the other requirements of, this Section 20. T

21. NOTICES

Any notice, or request, required by these Rules and Regulations or Terms and Conditions or the Agreement shall be deemed properly given if mailed, postage pre-paid, to Company, in the case of Company; or in the case of the Customer, to its representative designated in the Agreement. The designation of the person to be notified, and/or his address may be changed by Company or Customer at any time, or from time to time, by similar notice.

22. ADJUSTMENTS

Nothing contained herein or in any Agreement shall be construed as affecting in any way the right of Company, and Company shall at all times have the right, to unilaterally file with the Public Service Commission a change in rental charges for attachments to poles, other charges as provided for, any rule, regulation, condition or any other change required. Such change or changes to become effective upon approval of the Commission or applicable regulations or statutes, and shall constitute an amendment to the Agreement.

23. BINDING EFFECT

Subject to the provisions of Section 16 hereof, the Agreement and these Rules and Regulations or Terms and Conditions shall extend to and bind the successors and assigns of the parties hereto. T

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Special Charges

The following charges will be applied uniformly throughout Company's service territory. Each charge, as approved by the Public Service Commission, reflects only that revenue required to cover associated expenses.

RETURNED PAYMENT CHARGE

In those instances where a customer renders payment to Company which is not honored upon deposit by Company, the customer will be charged $10.00 to cover the additional processing costs.

METER TEST CHARGE

Where the test of a meter is performed during normal working hours upon the written request of a customer, pursuant to 807 KAR 5:006, Section 18, and the results show the meter was not more than two percent fast, the customer will be charged $75.00 to cover the test and transportation costs. I

DISCONNECT/RECONNECT SERVICE CHARGE

A charge of $28.00 will be made to cover disconnection and reconnection of electric service when discontinued for non-payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection. I

Residential and general service customers may request and be granted temporary suspension of electric service. In the event of such temporary suspension, Company will make a charge of $28.00 to cover disconnection and reconnection of electric service, such charge to be made before reconnection is effected. I

METER PULSE CHARGE

Where a customer desires and Company is willing to provide data meter pulses, a charge of $15.00 per month per installed set of pulse-generating equipment will be made to those data pulses. Time pulses will not be supplied. I

METER DATA PROCESSING CHARGE

A charge of $2.75 per report will be made to cover the cost of processing, generating, and providing recorder metered customer with profile reports. If a customer is not recorder metered and desires to have such metering installed, the customer will pay all costs associated with installing the recorder meter.

Standard Rate Rider **CSR10**
Curtailable Service Rider 10

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to customers served under applicable power schedules who contract for not less than 1,000 kilowatts individually. The aggregate service under P.S.C. No. 16, CSR10 and CSR30 for Kentucky Utilities Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 14, CSR1 and CSR3 for Kentucky Utilities Company as of August 1, 2010. T

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed three hundred and seventy-five (375) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time that may have both physical curtailments and buy-through options within the interval between the start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than ten (10) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year without a buy-through option. Company may also request at its sole discretion up to 275 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements. T

Curtailable load and compliance with a request for curtailment shall be measured in one of the following ways:

Option A -- Customer may contract for a given amount of firm demand, as measured on the demand basis of the standard rate on which Customer is billed. During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price, as applicable, shall apply to the difference in the actual kWh during any requested curtailment and the contracted firm demand multiplied by the time period (hours) of curtailment [Actual kWh – (firm kVA x hours curtailed)]. The measured demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance, as measured on the demand basis of the standard rate on which Customer is billed. T T T T

Option B -- Customer may contract for a given amount of curtailable load by which Customer shall agree to reduce its demand at any time by such Designated Curtailable Load. During a request for physical curtailment, Customer shall reduce its demand to a level equal to the maximum demand (as measured on the demand basis of the standard rate on which Customer is billed) immediately prior to the curtailment less the designated curtailable load. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price shall apply to the difference in the actual kWh during any requested curtailment and the product of Customer's maximum load immediately preceding curtailment less Customer's designated curtailable load designated in the contract multiplied by the time period (hours) of a requested curtailment {Actual kWh – [(Max kVA preceding – Designated Curtailable kVA) x hours of requested curtailment]}. Non-compliance for each requested physical curtailment shall be the measured positive value determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) the Customer's maximum demand during such curtailment. T T T

RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service	$ 2.75 per kVA of Curtailable Billing Demand	R/T
Primary Voltage Service	$ 2.80 per kVA of Curtailable Billing Demand	R/T
Non-Compliance Charge of:	$16.00 per kVA	T

Failure of Customer to curtail when requested to do so may result in termination of service under this rider. Customer will be charged for the portion of each requested curtailment not met at the applicable standard charges. The Company and Customer may arrange to have installed, at Customer's expense, the necessary telecommunication and control equipment to allow the Company to control Customers' curtailable load. Non-compliance charges will be waived if failure to curtail is a result of failure of Company's equipment; however, non-compliance charges will not be waived if failure to curtail is a result of Customer's equipment. If arrangements are made to have telecommunication and control equipment installed, then backup arrangements must also be established in the event either Company's or Customer's equipment fails.

CURTAILABLE BILLING DEMAND

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) the Customer's measured maximum kilowatt demand during the billing period for any billing interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M,(EST) and (ii) for the months October continuously through April, from 6 A.M. to 10 P.M, (EST) and (b) the firm contract demand. T

For a Customer electing Option B, Curtailable Billing Demand shall be the customer Designated Curtailable Load, as described above.

AUTOMATIC BUY-THROUGH PRICE

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP represents the mid-point price for natural gas ($/MMBtu) posted for the day in *Platts Gas Daily* for Dominion—South Point and will be used for the electrical day from 12 midnight to midnight. Also the posted price for Monday or the day after a holiday is the posted price for Saturday, Sunday and the holiday. T

TERM OF CONTRACT

The minimum original contract period shall be one (1) year and thereafter until terminated by giving at least six (6) months previous written notice, but Company may require that contract be executed for a longer initial term when deemed reasonably necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

When the Company requests curtailment, upon request by the Customer, the Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by the Company, the Customer shall provide to the Company a good-faith, non-binding short-term operational schedule for their facility. Upon request by the Customer, the Company will provide, once per month, to the Customer an explanation of the reasons for any request for curtailment.

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

Kentucky Utilities Company

Standard Rate Rider **CSR30**

Curtailable Service Rider 30

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to customers served under applicable power schedules who contract for not less than 1,000 kilowatts individually. The aggregate service under P.S.C. No. 16 , CSR10 and CSR30 for Kentucky Utilities Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 14, CSR1 and CSR3 for Kentucky Utilities Company as of August 1, 2010. T

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed three hundred and fifty (350) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time that may have both physical curtailments and buy-through options within the interval between the start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than thirty (30) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year without a buy-through option. Company may also request at its sole discretion up to 250 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements. T

Curtailable load and compliance with a request for curtailment shall be measured in one of the following ways:

Option A -- Customer may contract for a given amount of firm demand, as measured on the demand basis of the standard rate on which Customer is billed. During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price, as applicable, shall apply to the difference in the actual kWh during any requested curtailment and the contracted firm demand multiplied by the time period (hours) of curtailment [Actual kWh – (firm kVA x hours curtailed)]. The measured demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance, as measured on the demand basis of the standard rate on which Customer is billed. T T T T

Option B -- Customer may contract for a given amount of curtailable load by which Customer shall agree to reduce its demand at any time by such Designated Curtailable Load. During a request for physical curtailment, Customer shall reduce its demand to a level equal to the maximum demand (as measured on the demand basis of the standard rate on which Customer is billed) immediately prior to the curtailment less the designated curtailable load. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price shall apply to the difference in the actual kWh during any requested curtailment and the product of Customer's maximum load immediately preceding curtailment less Customer's designated curtailable load designated in the contract multiplied by the time period (hours) of a requested curtailment {Actual kWh – [(Max kVA preceding – Designated Curtailable kVA) x hours of requested curtailment]}. Non-compliance for each requested physical curtailment shall be the measured positive value determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) the Customer's maximum demand during such curtailment. T T T

RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service	\$ 2.25 per kVA of Curtailable Billing Demand	R/T
Primary Voltage Service	\$ 2.30 per kVA of Curtailable Billing Demand	R/T
Non-Compliance Charge of:	\$16.00 per kVA	T

Failure of Customer to curtail when requested to do so may result in termination of service under this rider. Customer will be charged for the portion of each requested curtailment not met at the applicable standard charges. The Company and Customer may arrange to have installed, at Customer's expense, the necessary telecommunication and control equipment to allow the Company to control Customers' curtailable load. Non-compliance charges will be waived if failure to curtail is a result of failure of Company's equipment; however, non-compliance charges will not be waived if failure to curtail is a result of Customer's equipment. If arrangements are made to have telecommunication and control equipment installed, then backup arrangements must also be established in the event either Company's or Customer's equipment fails.

CURTAILABLE BILLING DEMAND

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) the Customer's measured maximum kilowatt demand during the billing period for any billing interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M. (EST) and (ii) for the months October continuously through April, from 6 A.M. to 10 P.M, (EST) and (b) the firm contract demand. T

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CURTAILABLE BILLING DEMAND (continued) T

For a Customer electing Option B, Curtailable Billing Demand shall be the customer Designated Curtailable Load, as described above. T T

AUTOMATIC BUY-THROUGH PRICE

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP represents the mid-point price for natural gas ($/MMBtu) posted for the day in *Platts Gas Daily* for Dominion—South Point and will be used for the electrical day from 12 midnight to midnight. Also the posted price for Monday or the day after a holiday is the posted price for Saturday, Sunday and the holiday. T

TERM OF CONTRACT

The minimum original contract period shall be one (1) year and thereafter until terminated by giving at least six (6) months previous written notice, but Company may require that contract be executed for a longer initial term when deemed reasonably necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

When the Company requests curtailment, upon request by the Customer, the Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by the Company, the Customer shall provide to the Company a good-faith, non-binding short-term operational schedule for their facility. Upon request by the Customer, the Company will provide, once per month, to the Customer an explanation of the reasons for any request for curtailment.

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Standard Rate Rider **SQF**
Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE:
In all territory served.

AVAILABILITY OF SERVICE
This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy only from the owner of qualifying cogeneration or small power production facilities of 100 kW or less (such owner being hereafter called "Seller") installed on Seller's property to provide all or part of its requirements of electrical energy, or from which facilities Seller may elect to sell to Company all or part of such output of electrical energy.

Company will permit Seller's generating facilities to operate in parallel with Company's system under conditions set out below under “Parallel Operation”.

Company will purchase such energy from Seller at the Rate, A or B, set out below and selected as hereafter provided, and under the terms and conditions stated herein. Company reserves the right to change the said Rates, upon proper filing with and acceptance by the jurisdictional Commission.

RATE A: TIME-DIFFERENTIATED RATE

1. For summer billing months of June, July, August and September, during the hours 9:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours),	$0.04538 per kWh
2. For winter billing months of December, January and February, during the hours 7:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours),	$0.04023 per kWh
3. During all other hours (off-peak hours)	$0.03139 per kWh

Determination of On-Peak and Off-Peak Hours: On-peak hours are defined as the hours of 9:01 A.M. through 10:00 P.M., E.D.T. (8:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 1 above), and the hours of 7:01 A.M. through 10:00 P.M., E.D.T. (6:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 2 above). Off-peak hours are defined as all hours other than those listed as on-peak (under 3 above). Company reserves the right to change the hours designated as on-peak from time to time as conditions indicate to be appropriate.

RATE B: NON-TIME-DIFFERENTIATED RATE

For all kWh purchased by Company,	$0.03418 per kWh

SELECTION OF RATE AND METERING

Subject to provisions hereafter in this Section relative to payment of costs of metering equipment, either Seller or Company may select Rate A, the Time-Differentiated Rate, for application to Company's said purchases of energy from Seller. If neither Seller nor Company selects Rate A, then Rate B, the Non-Time-Differentiated Rate, shall apply.

If neither Seller nor Company selects Rate A, and Rate B therefore is to apply to such purchases, Company, at Seller's cost, will install, own and operate a non-time-differentiated meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system. Such meter will be tested at intervals prescribed by Commission Regulation, with Seller having a right to witness all such tests; and Seller will pay to Company its fixed cost on such meter and equipment, expense of such periodic tests of the meter and any other expenses (all such costs and expenses, together, being hereafter called "costs of non-time-differentiated metering").

If either Seller or Company selects Rate A to apply to Company's said purchases of energy from Seller, the party (Seller or Company) so selecting Rate A shall pay (a) the cost of a time-differentiated recording meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system, required for the application of Rate A, in excess of (b) the costs of non-time-differentiated metering which shall continue to be paid by Seller.

In addition to metering referred to above, Company at its option and cost may install, own and operate, on Seller's generator, a recording meter to record the capacity, energy and reactive output of such generator at specified time intervals.

Company shall have access to all such meters at reasonable times during Seller's normal business hours, and shall regularly provide to Seller copies of all information provided by such meters.

PAYMENT

Any payment due from Company to Seller will be due within twelve (12) days from date of Company's reading of meter; provided, however, that, if Seller is a customer of Company, in lieu of such payment Company may offset its payment due to Seller hereunder, against Seller's next bill and payment due to Company for Company's service to Seller as customer.

PARALLEL OPERATION

Company hereby permits Seller to operate its generating facilities in parallel with Company's system, under the following conditions and any other conditions required by Company where unusual conditions not covered herein arise:

1. Prior to installation in Seller's system of any generator and associated facilities which are intended to be interconnected and operated in parallel with Company's system, or prior to the inter-connection to Company's system of any such generator and associated facilities already installed in Seller's system, Seller will provide to Company plans for such generator

and facilities. Company may, but shall have no obligation to, examine such plans and disapprove them in whole or in part, to the extent Company believes that such plans and proposed facilities will not adequately assure the safety of Company's facilities or system. Seller acknowledges and agrees that the sole purpose of any Company examination of such plans is the satisfaction of Company's interest in the safety of Company's own facilities and system, and that Company shall have no responsibility of any kind to Seller or to any other party in connection with any such examination. If Seller thereafter proposes any change from such plans submitted to Company, prior to the implementation thereof Seller will provide to Company new plans setting out such proposed change(s).

2. Seller will own, install, operate and maintain all generating facilities on its plant site, such facilities to include, but not be limited to, (a) protective equipment between the systems of Seller and Company and (b) necessary control equipment to synchronize frequency and voltage between such two systems. Seller's voltage at the point of interconnection will be the same as Company's system voltage. Suitable circuit breakers or similar equipment, as specified by Company, will be furnished by Seller at a location designated by Company to enable the separation or disconnection of the two electrical systems. Except in emergencies, the circuit breakers, or similar equipment, will be operated only by, or at the express direction of, Company personnel and will be accessible to Company at all times. In addition, a circuit breaker or similar equipment shall be furnished and installed by Seller to separate or disconnect Seller's generator.

3. Seller will be responsible for operating the generator and all facilities owned by Seller, except as hereafter specified. Seller will maintain its system in synchronization with Company's system.

4. Seller will (a) pay Company for all damage to Company's equipment, facilities or system, and (b) save and hold Company harmless from all claims, demands and liabilities of every kind and nature for injury or damage to, or death of, persons and/or property of others, including costs and expenses of defending against the same, arising in any manner in connection with Seller's generator, equipment, facilities or system or the operation thereof.

5. Seller will construct any additional facilities, in addition to generating and associated (interface) facilities, required for interconnection unless Company and Seller agree to Company's constructing such facilities, at Seller's expense, where Seller is not a customer of Company. When Seller is a customer of Company and Company is required to construct facilities different than otherwise required to permit interconnection, Seller shall pay such additional cost of facilities. Seller agrees to reimburse Company, at the time of installation, or, if agreed to by both parties, over a period of up to three (3) years, for any facilities including any hereafter required (but exclusive of metering equipment, elsewhere herein provided for) constructed by Company to permit Seller to operate interconnected with Company's system. When interconnection costs are repaid over a period of time, such payments will be made monthly and include interest on the unpaid balance at the percentage rate equal to the capital costs that Company would experience at such time by new financing, based on Company's then existing capital structure, with return on equity to be at the rate allowed in Company's immediately preceding rate case.

6. Company will have the continuing right to inspect and approve Seller's facilities, described herein, and to request and witness any tests necessary to determine that such facilities are installed and operating properly; but Company will have no obligation to inspect or approve facilities, or to request or witness tests; and Company will not in any manner be responsible for Seller's facilities or any operation thereof.

7. Seller assumes all responsibility for the electric service upon Seller's premises at and from the point of any delivery or flow of electricity from Company, and for the wires and equipment used in connection therewith; and Seller will protect and save Company harmless from all claims for injury or damage to persons or property, including but not limited to property of Seller, occurring on or about Seller's premises or at and from the point of delivery or flow of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage is proved to have been caused solely by the negligence of Company.

8. Each, Seller and Company, will designate one or more Operating Representatives for the purpose of contacts and communications between the parties concerning operations of the two systems.

9. Seller will notify Company's Energy Control Center prior to each occasion of Seller's generator being brought into or (except in cases of emergencies) taken out of operation.

10. Company reserves the right to curtail a purchase from Seller when:

    (a) the purchase will result in costs to Company greater than would occur if the purchase were not made but instead Company, itself, generated an equivalent amount of energy; or

    (b) Company has a system emergency and purchases would (or could) contribute to such emergency.

    Seller will be notified of each curtailment.

TERMS AND CONDITIONS

Except as provided herein, conditions or operations will be as provided in Company's Terms and Conditions.

Standard Rate Rider **LQF**

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

AVAILABILITY

In all territory served.

APPLICABILITY OF SERVICE

Applicable to any small power production or cogeneration "qualifying facility" with capacity over 100 kW as defined by the Kentucky Public Service Commission Regulation 807 KAR 5:054, and which contracts to sell energy or capacity or both to Company.

RATES FOR PURCHASES FROM QUALIFYING FACILITIES

Energy Component Payments

The hourly avoided energy cost (AEC) in $ per MWh, which is payable to a QF for delivery of energy, shall be equal to Company's actual variable fuel expenses, for Company-owned coal and natural gas-fired production facilities, divided by the associated megawatt-hours of generation, as determined for the previous month. The total amount of the avoided energy cost payment to be made to a QF in an hour is equal to [AEC x E_{QF}], where E_{QF} is the amount of megawatt-hours delivered by a QF in that hour and which are determined by suitable metering.

Capacity Component Payments

The hourly avoided capacity cost (ACC) in $ per MWh, which is payable to a QF for delivery of capacity, shall be equal to the effective purchase price for power available to Company from the inter-utility market (which includes both energy and capacity charges) less Company's actual variable fuel expense (AEC). The total amount of the avoided capacity cost payment to be made to a QF in an hour is equal to [ACC x CAP_i], where CAP_i, the capacity delivered by the QF, is determined on the basis of the system demand (D_i) and Company's need for capacity in that hour to adequately serve the load.

Determination of CAP_i

For the following determination of CAP_i, C_{KU} represents Company's installed or previously arranged capacity at the time a QF signs a contract to deliver capacity; C_{QF} represents the actual capacity provided by a QF, but no more than the contracted capacity; and C_M represents capacity purchased from the inter-utility market.

1. System demand is less than or equal to Company's capacity:
   $D_1 \leq C_{KU}$; $CAP_i = 0$

2. System demand is greater than Company's capacity but less than or equal to the total of Company's capacity and the capacity provided by a QF:

   $C_{KU} < D_i \leq [C_{KU} + C_{QF}]$; $CAP_i = C_M$

3. System demand is greater than the total of Company's capacity and the capacity provided by a QF:

   $D_i > [C_{KU} + C_{QF}]$; $CAP_i = C_{QF}$

PAYMENT

Company shall pay each bill for electric power rendered to it in accordance with the terms of the contract, within twelve (12) days of the date the bill is rendered. In lieu of such payment plan, Company will, upon written request, credit the Customer's account for such purchases.

TERM OF CONTRACT

For contracts which cover the purchase of energy only, the term shall be one (1) year, and shall be self-renewing from year-to-year thereafter, unless canceled by either party on one (1) year's written notice.

For contracts which cover the purchase of capacity and energy, the term shall be five (5) years.

TERMS AND CONDITIONS

1. Qualifying facilities shall be required to pay for any additional interconnection costs, to the extent that such costs are in excess of those that Company would have incurred if the qualifying facility's output had not been purchased.

2. A qualifying facility operating in parallel with Company must demonstrate that its equipment is designed, installed, and operated in a manner that insures safe and reliable interconnected operation. A qualifying facility should contact Company for assistance in this regard.

3. The purchasing, supplying and billing for service, and all conditions applying hereto, shall be specified in the contract executed by the parties, and are subject to the jurisdiction of the Kentucky Public Service Commission, and to Company's Terms and Conditions currently in effect, as filed with the Commission.

Standard Rate Rider **NMS**
Net Metering Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to any customer-generator who owns and operates a generating facility located on Customer's premises that generates electricity using solar, wind, biomass or biogas, or hydro energy in parallel with Company's electric distribution system to provide all or part of Customer's electrical requirements, and who executes Company's written Application for Interconnection and Net Metering. The generation facility shall be limited to a maximum rated capacity of 30 kilowatts. This Standard Rate Rider is intended to comply with all provisions of the Interconnection and Net Metering Guidelines approved by the Public Service Commission of Kentucky, which can be found on-line at www.psc.ky.gov as Appendix A to the January 8, 2009 Order in Administrative Case No. 2008-00169.

METERING AND BILLING

Net metering service shall be measured using a single meter or, as determined by Company, additional meters and shall be measured in accordance with standard metering practices by metering equipment capable of registering power flow in both directions for each time period defined by the applicable rate schedule. This net metering equipment shall be provided without any cost to the Customer. This provision does not relieve Customer's responsibility to pay metering costs embedded in the Company's Commission-approved base rates. Additional meters, requested by Customer, will be provided at Customer's expense.

If electricity generated by Customer and fed back to Company's system exceeds the electricity supplied to Customer from the system during a billing period, Customer shall receive a credit for the net delivery on Customer's bill for the succeeding billing periods. Any such unused excess credits will be carried forward and drawn on by Customer as needed. Unused excess credits existing at the time Customer's service is terminated end with Customer's account and are not transferrable between customers or locations.

NET METERING SERVICE INTERCONNECTION GUIDELINES

General – Customer shall operate the generating facility in parallel with Company's system under the following conditions and any other conditions required by Company where unusual circumstances arise not covered herein:

1. Customer to own, operate, and maintain all generating facilities on their premises. Such facilities shall include, but not be limited to, necessary control equipment to synchronize frequency, voltage, etc., between Customer's and Company's system as well as adequate protective equipment between the two systems. Customer's voltage at the point of interconnection will be the same as Company's system voltage.
2. Customer will be responsible for operating all generating facilities owned by Customer, except as specified hereinafter. Customer will maintain its system in synchronization with Company's system.
3. Customer will be responsible for any damage done to Company's equipment due to failure of Customer's control, safety, or other equipment.
4. Customer agrees to inform Company of any changes it wishes to make to its generating or associated facilities that differ from those initially installed and described to Company in writing and obtain prior approval from Company.
5. Company will have the right to inspect and approve Customer's facilities described herein, and to conduct any tests necessary to determine that such facilities are installed and

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

operating properly; however, Company will have no obligation to inspect, witness tests, or in any manner be responsible for Customer's facilities or operation thereof.

6. Customer assumes all responsibility for the electric service on Customer's premises at and from the point of delivery of electricity from Company and for the wires and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence or willful misconduct of Company.

Level 1 – A Level 1 installation is defined as an inverter-based generator certified as meeting the requirements of Underwriters Laboratories Standard 1741 and meeting the following conditions:

1. The aggregated net metering generation on a radial distribution circuit will not exceed 15% of the line section's most recent one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
2. The aggregated net metering generation on a shared singled-phase secondary will not exceed 20 kVA or the nameplate rating of the service transformer.
3. A single-phase net metering generator interconnected on the center tap neutral of a 240 volt service shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.
4. A net metering generator interconnected to Company's three-phase, three-wire primary distribution lines, shall appear as a phase-to-phase connection to Company's primary distribution line.
5. A net metering generator interconnected to Company's three-phase, four-wire primary distribution lines, shall appear as an effectively grounded source to Company's primary distribution line.
6. A net metering generator will not be connected to an area or spot network.
7. There are no identified violations of the applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems".
8. Company will not be required to construct any facilities on its own system to accommodate the net metering generator.

Customer desiring a Level 1 interconnection shall submit a "LEVEL 1 - Application for Interconnection and Net Metering." Company shall notify Customer within 20 business days as to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, the Company will notify Customer, and the time between notification and submission of the information shall not be counted towards the 20 business days. Approval is contingent upon an initial inspection and witness test at the discretion of Company.

Level 2 – A Level 2 installation is defined as generator that is not inverter-based; that uses equipment not certified as meeting the requirements of Underwriters Laboratories Standard 1741, or that does not meet one or more of the conditions required of a Level 1 net metering generator. A Level 2 Application will be approved if the generating facility meets the Company's technical interconnection requirements. Those requirements are available on line at www.lge-ku.com and upon request.

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

Customer desiring a Level 2 interconnection shall submit a "LEVEL 2 - Application for Interconnection and Net Metering." Company shall notify Customer within 30 business days as to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, the Company will notify Customer, and the time between notification and submission of the information shall not be counted towards the 30 business days. Approval is contingent upon an initial inspection and witness test at the discretion of Company.

Customer submitting a "Level 2 - Application for Interconnection and Net Metering will provide a non-refundable inspection and processing fee of $100, and in the event that the Company determines an impact study to be necessary, shall be responsible for any reasonable costs of up to $1,000 of documented costs for the initial impact study.

Additional studies requested by Customer shall be at Customer's expense.

CONDITIONS OF INTERCONNECTION

Customer may operate his net metering generator in parallel with Company's system when complying with the following conditions:

1. Customer shall install, operate, and maintain, at Customer's sole cost and expense, any control, protective, or other equipment on Customer's system required by Company's technical interconnection requirements based on IEEE 1547, NEC, accredited testing laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the net metering generating facility in parallel with Company's system. Customer bears full responsibility for the installation, maintenance and safe operation of the net metering generating facility. Upon reasonable request from Company, Customer shall demonstrate compliance.
2. Customer shall represent and warrant compliance of the net metering generator with:
   a) any applicable safety and power standards established by IEEE and accredited testing laboratories;
   b) NEC, as may be revised from time-to-time;
   c) Company's rules and regulations and Terms and Conditions, as may be revised by time-to-time by the Public Service Commission of Kentucky;
   d) the rules and regulations of the Public Service Commission of Kentucky, as may be revised by time-to-time by the Public Service Commission of Kentucky:
   e) all other local, state, and federal codes and laws, as may be in effect from time-to-time.
3. Any changes or additions to Company's system required to accommodate the net metering generator shall be Customer's financial responsibility and Company shall be reimbursed for such changes or additions prior to construction.
4. Customer shall operate the net metering generator in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. Customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system.
5. Customer shall be responsible for protecting, at Customer's sole cost and expense, the net metering generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the net metering

CONDITIONS OF INTERCONNECTION (continued)

generator resulting solely from the negligence or willful misconduct on the part of the Company.

6. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to Customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the net metering generator comply with the requirements of this rate schedule.
7. Where required by the Company, Customer shall furnish and install on Customer's side of the point of interconnection a safety disconnect switch which shall be capable of fully disconnecting Customer's net metering generator from Company's electric service under the full rated conditions of Customer’s net metering generator. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, Customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the net metering generator is operational. The disconnect switch shall be accessible to Company personnel at all times. Company may waive the requirement for an external disconnect switch for a net metering generator at its sole discretion, and on a case by case basis.
8. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the Customer to discontinue operation of the net metering generator if Company believes that:
   a) continued interconnection and parallel operation of the net metering generator with Company’s electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or Customer's electric system;
   b) the net metering generator is not in compliance with the requirements of this rate schedule, and the non-compliance adversely affects the safety, reliability or power quality of Company’s electric system; or
   c) the net metering generator interferes with the operation of Company's electric system.

   In non-emergency situations, Company shall give Customer notice of noncompliance including a description of the specific noncompliance condition and allow Customer a reasonable time to cure the noncompliance prior to isolating the Generating Facilities. In emergency situations, where the Company is unable to immediately isolate or cause Customer to isolate only the net metering generator, Company may isolate Customer’s entire facility.
9. Customer agrees that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in net metering generator capacity will require a new “Application for Interconnection and Net Metering” which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in net metering generator capacity is allowed without approval.
10. Customer shall protect, indemnify and hold harmless Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by Customer or Customer’s employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating

CONDITIONS OF INTERCONNECTION (continued)

Customer's net metering generator or any related equipment or any facilities owned by Company except where such injury, death or damage was caused or contributed to by the fault or negligence of Company or its employees, agents, representatives or contractors.

The liability of Company to Customer for injury to person and property shall be governed by the tariff(s) for the class of service under which Customer is taking service.

11. Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial or other policy) for generating facilities. Customer shall upon request provide Company with proof of such insurance at the time that application is made for net metering.
12. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.
13. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify Customer in writing and list what must be done to place the facility in compliance.
14. Customer shall retain any and all Renewable Energy Credits (RECs) generated by Customer's generating facilities.

DEFINITIONS

"Billing period" shall be the time period between the dates on which Company issues the customer's bills.

"Billing Period Credit" shall be the electricity generated by the customer that flows into the electric system and which exceeds the electricity supplied to the customer from the electric system during any billing period.

TERMS AND CONDITIONS

Except as provided herein, service will be furnished under Company's Terms and Conditions applicable hereto.

LEVEL 1

Application for Interconnection and Net Metering

*Use this application form only for a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of **UL** 1741.*

Submit this Application to:

Kentucky Utilities Company, Attn: Customer Commitment, P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact KU at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ______________________ Account Number: ______________________

Customer Address: ____

Customer Phone No.: ______________ Customer E-mail Address: ______________________

Project Contact Person: ____

Phone No.**:** ______________ E-mail Address (Optional): ______________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

Energy Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Inverter Manufacturer and Model #: ____

Inverter Power Rating: ______________ Inverter Voltage Rating: ______________________

Power Rating of Energy Source (i.e., solar panels, wind turbine): ______________________

Is Battery Storage Used: ____No _____Yes If Yes, Battery Power Rating: ______________________

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of **UL** 1741.

Attach site drawing or sketch showing location of Utility's meter, energy source, ***(optional: Utility accessible disconnect switch)*** and inverter.

Attach single line drawing showing all electrical equipment from the Utility's metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ______________________

LEVEL 2

Application for Interconnection and Net Metering

*Use this application form when a generating facility is not inverter-based or is not certified by a nationally recognized testing laboratory to meet the requirements of **UL** 1741 or does not meet any of the additional conditions under Level 1.*

Submit this Application, along with an application fee of $100, to:

Kentucky Utilities Company, Attn: Customer Commitment, P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact KU at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ______________________ Account Number: ______________

Customer Address: ______________________________________

Project Contact Person: ______________________________________

Phone No.: ______________ E-mail Address (Optional): ______________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

____

____

Total Generating Capacity of Generating Facility: ______________________

Type of Generator: ____Inverter-Based ____Synchronous ____Induction

Power Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Adequate documentation and information must be submitted with this application to be considered complete. Typically this should include the following:

1. Single-line diagram of the customer's system showing all electrical equipment from the generator to the point *of* interconnection with the Utility's distribution system, including generators, transformers, switchgear, switches, breakers, fuses, voltage transformers, current transformers, wire sizes, equipment ratings, and transformer connections.
2. Control drawings for relays and breakers.
3. Site Plans showing the physical location of major equipment.
4. Relevant ratings of equipment. Transformer information should include capacity ratings, voltage ratings, winding arrangements, and impedance.
5. If protective relays are used, settings applicable to the interconnection protection. If programmable relays are used, a description of how the relay is programmed to operate as applicable to interconnection protection.
6. A description of how the generator system will be operated including all modes of operation.
7. For inverters, the manufacturer name, model number, and AC power rating. For certified inverters, attach documentation showing that inverter is certified by *a* nationally recognized testing laboratory to meet the requirements of **UL** 1741.
8. For synchronous generators, manufacturer and model number, nameplate ratings, and impedance data (Xd, Xd, & Xd).
9. For induction generators, manufacturer and model number, nameplate ratings, and locked rotor current.

Customer Signature: ______________________ Date: ______________

Excess Facilities

APPLICABILITY

In all territory served.

AVAILABILITY OF SERVICE

This rider is available for nonstandard service facilities which are considered to be in excess of the standard facilities that would normally be provided by Company. This rider does not apply to line extensions or to other facilities which are necessary to provide basic electric service. Company reserves the right to decline to provide service hereunder for any project (a) that exceeds $100,000 or (b) where Company does not have sufficient expertise to install, operate, or maintain the facilities or (c) where the facilities do not meet Company's safety requirements, or (d) where the facilities are likely to become obsolete prior to the end of the initial contract term.

DEFINITION OF EXCESS FACILITIES

Excess facilities are lines and equipment which are installed in addition to or in substitution for the normal facilities required to render basic electric service and where such facilities are T
dedicated to a specific customer. Applications of excess facilities include, but are not limited to, T
emergency backup feeds, automatic transfer switches, redundant transformer capacity, and duplicate or check meters.

EXCESS FACILITIES CHARGE

Company shall provide normal operation and maintenance of the excess facilities. Should the facilities suffer failure, Company will provide for replacement of such facilities and the monthly charge will be adjusted to reflect the installed cost of the replacement facilities. No adjustment T
in the monthly charge for a replacement of facilities will be made during the initial five (5) year T
term of contract. T

Customer shall pay for excess facilities by: T

(a) making a monthly Excess Facilities Charge payment equal to the installed cost of the T
excess facilities times the following percentage: T

Percentage With No Contribution–in-Aid-of-Construction	1.28%	T/R

(b) making a one-time Contribution-in-Aid-of-Construction equal to the installed cost of the T
excess facilities plus a monthly Excess Facilities Charge payment equal to the installed T
cost of the excess facilities times the following percentage: T

Percentage With Contribution-in-Aid of-Construction	0.49%	T/R

PAYMENT

The Excess Facilities Charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

TERM OF CONTRACT

The initial term of contract to the customer under this schedule shall be not less than five (5) years. The term shall continue automatically until terminated by either party upon at least one (1) month's written notice.

APPLICABLE

This rate is applicable to customers served under Company's rate schedules which include a demand charge or a special contract including a demand charge.

AVAILABILITY

Available to customers requesting the reservation of capacity on Company's facilities which are shared by other customers when Company has and is willing to reserve such capacity. Such facilities represent a redundant delivery to provide electric service to the Customer's facility in the event that an emergency or unusual occurrence renders the Customer's principal delivery unavailable for providing service. Where Customer desires to split a load between multiple meters on multiple feeds and contract for Redundant Capacity on those feeds, service is contingent on the practicality of metering to measure any transferred load to the redundant feed. T T T T

RATE:

Capacity Reservation Charge

Secondary Distribution	$1.55 per kW/kVA per month	I/T
Primary Distribution	$0.99 per kW/kVA per month	I/T

Applicable to the greater of:

(1) the highest average load in kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) recorded at either the principal distribution feed metering point or at the redundant distribution feed metering point during any 15-minute interval in the monthly billing period; T T

(2) 50% of the maximum demand similarly determined for any of the eleven (11) preceding months; or

(3) the contracted capacity reservation.

TERM OF CONTRACT

The minimum contract term shall be five (5) years and shall be renewed for one-year periods until either party provides the other with ninety (90) days written notice of a desire to terminate the arrangement. Company may require that a contract be executed for a longer initial term when deemed necessary by the difficulty and/or high cost associated with providing the redundant feed or other special conditions.

Standard Rate Rider **SS**

Supplemental or Standby Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This service is available as a rider to customers whose premises or equipment are regularly supplied with electric energy from generating facilities other than those of Company and who desire to contract with Company for reserve, breakdown, supplemental or standby service.

Where a customer-generator supplies all or part of the customer-generator's own load and desires Company to provide supplemental or standby service for that load, the customer-generator must contract for such service under Company's Supplemental or Standby Service Rider, otherwise Company has no obligation to supply the non-firm service. This requirement does not apply to Net Metering Service (Rider NMS). T

RATE

	Secondary	Primary	Transmission	
Contract Demand per kW/kVA per Month	$12.91	$12.35	$11.17	T/I

CONTRACT DEMAND

Contract Demand is defined as the number of kW/kVA (as is appropriate for the demand basis T
of the standard rate on which Customer is billed) mutually agreed upon as representing T
customer's maximum service requirements and contracted for by customer; provided, however,
if such number of kW/kVA (as is appropriate for the demand basis of the standard rate on which T
Customer is billed) is exceeded by a recorded demand, such recorded demand shall become T
the new contract demand commencing with the month in which recorded and continuing for the remaining term of the contract or until superseded by a higher recorded demand.

MINIMUM CHARGE

Electric service actually used each month will be charged for in accordance with the provisions of the applicable rate schedule; provided, however, the minimum billing under that rate schedule shall in no case be less than an amount calculated at the appropriate rate above applied to the Contract Demand.

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

SPECIAL TERMS AND CONDITIONS

1) In order to protect its equipment from overload damage, Company may require customer to install at Customer's own expense an approved shunt trip type breaker and an approved automatic pole-mounted disconnect. Such circuit breakers shall be under the sole control of Company and will be set by Company to break the connection with its service in the event customer's demand materially exceeds that for which the customer contracted.

T

SPECIAL TERMS AND CONDITIONS (continued)

2) In the event customer's use of service is intermittent or subject to violent fluctuations, Company will require customer to install and maintain at Customer's own expense suitable equipment to satisfactorily limit such intermittence or fluctuations. T T T

3) Customer's generating equipment shall not be operated in parallel with Company's service until the manner of such operation has been approved by Company and is in compliance with Company's operating standards for system reliability and safety.

TERM OF CONTRACT
The minimum contract period shall be one (1) year, but Company may require that a contract be executed for a longer initial term when deemed necessary by the size of load or special conditions.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions except as provided herein.

Standard Rate Rider **IL**

Rider for Intermittent Loads

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule applies to all loads having a detrimental effect upon the electric service rendered to other customers of Company or upon Company's facilities.

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company, in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other desirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 14(1)(b). Such a termination of service T shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. Company shall be held harmless for any damages or economic loss resulting from such termination of service. If requested by Company, Customer shall provide all available information to Company that aids Company in enforcing its service standards. If Company at any time has a reasonable basis for believing that Customer's proposed or existing use of the service provided will not comply with the service standards for interference, fluctuations, or harmonics, Company may engage such experts and/or consultants as Company shall determine are appropriate to advise Company in ensuring that such interference, fluctuations, or harmonics are within acceptable standards. Should such experts and/or consultants determine Customer's use of service is unacceptable, Company's use of such experts and/or consultants will be at the Customer's expense.

RATE

1. A contribution in aid of construction or an excess facilities charge shall be required for all special or added facilities, if any, necessary to serve such loads, as provided under the Excess Facilities Rider.
2. Plus the charges provided for under the rate schedule applicable, including any Basic Service Charge if applicable, Energy Charge, Maximum Load Charge (if load charge rate is used), Fuel Clause and the Minimum Charge under such rate adjusted in accordance with (a) or (b) herein.
   (a) If rate schedule calls for a minimum based on the total kW of connected load, each kVA of such special equipment shall be counted as one kW connected load for minimum billing purposes.
   (b) If rate schedule calls for a minimum based on the 15-minute integrated load, and such loads operate only intermittently so that the kW registered on a standard 15-minute integrated demand meter is small in comparison to the instantaneous load such equipment is capable of imposing, each kVA of such special equipment shall be counted as one-third kW load for minimum billing purposes.

MINIMUM CHARGE

As determined by this Rider and the Rate Schedule to which it is attached.

Standard Rate Rider **TS**

Temporary and/or Seasonal Electric Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider is available at the option of Customer where Customer's business does not require permanent installation of Company's facilities and is of such nature to require: T T

1. only seasonal service or temporary service, including service provided for construction of residences or commercial buildings, and where in the judgment of Company the local and system electrical facility capacities are adequate to serve the load without impairment of service to other customers; or
2. where Customer has need for temporary use of Company facilities and Company has facilities it is willing to provide.

This service is available for not less than one (1) month (approximately thirty (30) days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes.

CONDITIONS

Company may permit such electric loads to be served on the rate schedule normally applicable, but without requiring a yearly contract and minimum, substituting therefor the following conditions and agreements:

1. Customer shall pay Company for all costs of making temporary connections, including cost of installing necessary transformers, meters, poles, wire and any other material, and any cost of material which cannot be salvaged, and the cost of removing such facilities when load has ceased.

2. Customer shall pay regular rate of the applicable electric rate schedule.

3. Where Customer is receiving service under a standard rate and has need for temporary use of Company facilities, Customer will pay for non-salvageable materials outlined in (1) above plus a monthly charge for the salvageable equipment at the Percentage With No Contribution -in-Aid-of-Construction specified on the Excess Facilities Rider, Rate Sheet No. 60. T T T

Standard Rate Rider

Kilowatt-Hours Consumed By Lighting Units

APPLICABLE

Determination of energy set out below applies to the Company's non-metered lighting rate schedules.

DETERMINATION OF ENERGY CONSUMPTION

The applicable fuel clause charge or credit will be based on the kilowatt-hours calculated by multiplying the kilowatt load of each light times the number of hours that light is in use during the billing month. The kilowatt load of each light is shown in the section titled RATE. The number of hours a light will be in use during a given month is from dusk to dawn as shown in the following Hours Use Table.

HOURS USE TABLE

Month	Hours Light Is In Use
JAN	407
FEB	344
MAR	347
APR	301
MAY	281
JUN	257
JUL	273
AUG	299
SEP	322
OCT	368
NOV	386
DEC	415
TOTAL FOR YEAR	4,000 HRS.

Standard Rate Rider

SGE
Small Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard RS or GS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.
b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one (1) MWh of green power.

RATE

Voluntary monthly contributions of any amount in $5.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $5.00 increments (e.g., $5.00, $10.00, $15.00, or more per month). An eligible customer may participate in Company's "Green Energy Program" by making a request to Company's Call Center or through Company's website enrollment form and may withdraw at any time through a request to Company's Call Center. Funds provided by Customer to Company are not refundable.
b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any Customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one (1) year.
c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard PS, TODS, TODP, RTS, or FLS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates. T

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.
b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one (1) MWh of green power.

RATE

Voluntary monthly contributions of any amount in $13.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $13.00 increments, (e.g., $13.00, $26.00, $39.00, or more per month). An eligible customer may participate in company's "Green Energy Program" by making a request to the Company and may withdraw at any time through a request to the Company. Funds provided by Customer to Company are not refundable.
b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one (1) year.
c) Customer will be billed monthly for the amount customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

Standard Rate Rider **EDR**
Economic Development Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available as a rider to customers to be served or being served under Company's Standard Rate Schedules TODS, TODP, and RTS to encourage Brownfield Development or Economic Development (as defined herein). Service under EDR is conditional on approval of a special contract for such service filed with and approved by the Public Service Commission of Kentucky.

RATE

A customer taking service under EDR shall be served according to all of the rates, terms, and conditions of the normally applicable rate schedule subject to the following:

a) for the twelve consecutive monthly billings of the first contract year, the Total Demand Charge shall be reduced by 50%;
b) for the twelve consecutive monthly billings of the second contract year, the Total Demand Charge shall be reduced by 40%;
c) for the twelve consecutive monthly billings of the third contract year, the Total Demand Charge shall be reduced by 30%;
d) for the twelve consecutive monthly billings of the fourth contract year, the Total Demand Charge shall be reduced by 20%;
e) for the twelve consecutive monthly billings of the fifth contract year, the Total Demand Charge shall be reduced by 10%; and
f) all subsequent billing shall be at the full charges stated in the applicable rate schedule.

"Total Demand Charge" is the sum of all demand charges, including any credits provided under any other demand applicable rider, before the EDR discounts described above are applied.

TERMS AND CONDITIONS

Brownfield Development

a) Service under EDR for Brownfield Development is available to customers locating at sites that have been submitted to, approved by, and added to the Brownfield Inventory maintained by the Kentucky Energy and Environment Cabinet (or by any successor entity created and authorized by the Commonwealth of Kentucky).
b) EDR for Brownfield Development is available only to billing loads of 500 kVA or greater where the customer takes service from existing Company facilities.

Economic Development

c) Service under EDR for Economic Development is available to:
    1) new customers contracting for a minimum annual average of monthly billing load of 1,000 kVA; and
    2) existing customers contracting for a minimum annual average of monthly billing load of 1,000 kVA above their Existing Base Load, to be determined as follows:

TERMS AND CONDITIONS, Economic Development c) 2) (continued)

i. Company and the existing customer will determine Customer's Existing Base Load by averaging Customer's previous three years' monthly billing loads, subject to any mutually agreed upon adjustments thereto.
ii. Company and the existing customer must agree upon the Existing Base Load, which shall be an explicit term of the special contract submitted to the Commission for approval before the customer can take service under EDR. Once the Existing Base Load's value is thus established, it will not be subject to variation or eligible for service under EDR.
iii. This provision is not intended to reduce or diminish in any way EDR service already being provided to all or a portion of a customer's Existing Base Load. Such EDR service would continue under the terms of the contract already existing between the Company and the customer concerning the affected portion of the customer's Existing Base Load.

d) A customer desiring service under EDR for Economic Development must submit an application for service that includes:
   1) a description of the new load to be served;
   2) the number of new employees, if any, Customer anticipates employing associated with the new load;
   3) the capital investment Customer anticipates making associated with the EDR load;
   4) a certification that Customer has been qualified by the Commonwealth of Kentucky for benefits under the Kentucky Business Investment Program.

e) Should Company determine a refundable contribution for the capital investment in Customer-specific facilities required by Company to serve the EDR load would ordinarily be required as set out under Company's Line Extension Plan, I. Special Cases, that amount shall be determined over a fifteen (15) year period and payable at the end of the fifteen (15) year period.

General

f) Company may offer EDR to qualifying new load only when Company has generating capacity available and the new load will not accelerate Company's plans for additional generating capacity over the life of the EDR contract.
g) Customer may request an EDR effective initial billing date that is no later than twelve (12) months after the date on which Company initiates service to Customer.
h) Neither the demand charge reduction nor any unjustified capital investment in facilities will be borne by Company's other customers during the term of the EDR contract.
i) Company may offer differing terms, as appropriate, under special contract to which this rider is a part depending on the circumstances associated with providing service to a particular customer and subject to approval by the Public Service Commission of Kentucky.

TERM OF CONTRACT

Service will be furnished under the applicable standard rate schedule and this rider, filed as a special contract with the Commission for a fixed term of not less than ten (10) years and for such time thereafter under the terms stated in the standard rate schedule. A greater term of contract or termination notice may be required because of conditions associated with a Customer's requirements for service. Service will be continued under conditions provided for under the rate schedule to which this Rider is attached after the original term of contract.

Standard Rate **LEV**
Low Emission Vehicle Service

APPLICABLE
In the territory served.

AVAILABILITY OF SERVICE
LEV shall be available as option to customers otherwise served under rate schedule RS to encourage off-peak power for low emission vehicles.

1) LEV is a three year pilot program that may be restricted to a maximum of one hundred (100) customers eligible for Rate RS (or GS where the GS service is used in conjunction with an RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month) in any year and shall remain in effect until modified or terminated by order of the Commission. Company will accept applications on a first-come-first-served basis. T T T
2) This service is restricted to customers who demonstrate power delivered to premises is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include:
   a) battery electric vehicles or plug-in hybrid electric vehicles recharged through a charging outlet at Customer's premises,
   b) natural gas vehicles refueled through an electric-powered refueling appliance at Customer's premises.
3) A customer exiting the pilot program or disconnected for non-payment may not be allowed to return to it until the Commission has issued a decision on the pilot program report.
4) Company will file a report on LEV with the Commission within six months after the first three years of implementation of the pilot program. Such report will detail findings and recommendations.

RATE

Basic Service Charge:	$13.00 per month	I
Plus an Energy Charge:		
Off Peak Hours:	$0.05078 per kWh	I
Intermediate Hours:	$0.07254 per kWh	I
Peak Hours:	$0.13788 per kWh	I

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

DETERMINATION OF PRICING PERIODS

Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends. The hours of the pricing periods for the price levels are as follows:

Summer Months of May through September

	Off-Peak	Intermediate	Peak
Weekdays	10 PM - 10 AM	10 AM - 1 PM 7 PM - 10 PM	1 PM - 7 PM
Weekends	All Hours		

All Other Months of October continuously through April

	Off Peak	Intermediate	Peak
Weekdays	10 PM - 6 AM	12 Noon – 10 PM	6 AM – 12 Noon
Weekends	All Hours		

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer’s payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month’s charges.

TERMS OF CONTRACT

For a fixed term of not less than one (1) year and for such time thereafter until terminated by either party giving thirty (30) days written notice to the other of the desire to terminate.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional pilot program will not be eligible for Company’s Budget Payment Plan. Company shall install metering equipment capable of accommodating the Time of Use rate described herein.

Adjustment Clause **FAC**
Fuel Adjustment Clause

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all electric rate schedules.

(1) The charge per kWh delivered under the rate schedules to which this fuel clause is applicable shall be increased or decreased during each month in accordance with the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

where "F" is the expense of fossil fuel and "S" is the kWh sales in the base (b) and current (m) periods as defined in 807 KAR 5:056, all as set out below.

(2) Fuel costs (F) shall be the most recent actual monthly cost of:

(a) Fossil fuel consumed in the utility's own plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation; plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute for the forced outages; plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) The cost of fossil fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(e) All fuel costs shall be based on weighted average inventory costing.

(3) Forced outages are all non-scheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel cost of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel cost (F) in subsection (2)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation. T

Adjustment Clause **FAC**
Fuel Adjustment Clause

(4) Sales (S) shall be all kWh sold, excluding inter-system sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) inter-system sales referred to in subsection (2)(d) above, less (vi) total system losses. Utility used energy shall not be excluded in the determination of sales (S). T

(5) The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees.

(6) Base (b) period shall be the twelve (12) months ending October 2010 and the base fuel factor is $0.02668 per kWh.

(7) Current (m) period shall be the second month preceding the month in which the Fuel Clause Adjustment Factor is billed.

(8) Pursuant to the Public Service Commission's Order in Case No. 2010-00492 dated May 31, 2011, the Fuel Adjustment Clause will become effective with bills rendered on and after the first billing cycle for July 2011, which begins June 29, 2011.

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to Residential Rate RS, Volunteer Fire Department Service Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Low Emission Vehicle Service Rate LEV. Industrial customers who elect not to participate in a demand-side management program hereunder shall not be assessed a charge pursuant to this mechanism. For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are primarily engaged in a process or processes that create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32, and 33. All other non-residential customers will be defined as "commercial." T

RATE

The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per kilowatt hour of monthly consumption in accordance with the following formula:

DSMRC = DCR + DRLS + DSMI + DBA + DCCR

Where:

DCR = DSM COST RECOVERY

The DCR shall include all expected costs that have been approved by the Commission for each twelve-month period for demand-side management programs that have been developed through a collaborative advisory process ("approved programs"). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs. Program costs will be assigned for recovery purposes to the rate classes whose customers are directly participating in the program. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees, and administrative expenses, will be recovered through the DCR. Administrative costs that are allocable to more than one rate class will be recovered from those classes and allocated by rate class on the basis of the estimated budget from each program. The cost of approved programs shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DCR for each such rate class.

DRLS = DSM REVENUE FROM LOST SALES

Revenues from lost sales due to DSM programs implemented on and after the effective date of this tariff will be recovered as follows:

1) For each upcoming twelve-month period, the estimated reduction in customer usage (in kWh) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per kWh for purposes of determining the lost revenue to be recovered hereunder from each customer class. The non-variable revenue requirement for the Residential, Volunteer Fire Department, General Service, All Electric School, and Low Emission Vehicle customer classes is defined as the weighted average price per kWh of expected billings under the energy charges contained in the

RATE (continued)

RS, VFD, GS, AES, and LEV rate schedules in the upcoming twelve-month period after deducting the variable costs included in such energy charges. The non-variable revenue requirement for each of the customer classes that are billed under demand and energy rates (rate schedules PS, TODS, and TODP) is defined as the weighted average price per kWh represented by the composite of the expected billings under the respective demand and energy charges in the upcoming twelve-month period, after deducting the variable costs included in the energy charges.

2) The lost revenues for each customer class shall then be divided by the estimated class sales (in kWh) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenue from lost sales calculated for a twelve-month period shall be included in the DRLS for 36 months or until implementation of new rates pursuant to a general rate case, whichever comes first. Revenues from lost sales will be assigned for recovery purposes to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation, and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

DSMI = DSM INCENTIVE

For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved programs that are to be installed during the upcoming twelve-month period times fifteen (15) percent, not to exceed five (5) percent of program expenditures. Net resource savings are defined as program benefits less utility program costs and participant costs where program benefits will be calculated on the basis of the present value of Company's avoided costs over the expected life of the program, and will include both capacity and energy savings. For the Energy Education Program, the DSM incentive amount shall be computed by multiplying the annual cost of the approved program times five (5) percent.

The DSM incentive amount related to programs for Residential Rate RS, Volunteer Fire Department Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Rate PS, Time-of-day Secondary Service Rate TODS, Time-of-Day Primary Rate TODP, and Low Emission Vehicle Service Rate LEV shall be divided by the expected kilowatt-hour sales for T
the upcoming twelve-month period to determine the DSMI for such rate class. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

DBA = DSM BALANCE ADJUSTMENT

The DBA shall be calculated on a calendar-year basis and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, DCCR, and previous application of the DBA and the revenues that should have been billed, as follows:

1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.
2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.
3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.
4) For the DBA, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DBA and the balance adjustment amount established for the same twelve-month period.

The balance adjustment amounts determined on the basis of the above paragraphs (1)-(4) shall include interest applied to the monthly amounts, such interest to be calculated at a rate equal to the average of the “Three-Month Commercial Paper Rate” for the immediately preceding twelve-month period. The total of the balance adjustment amounts shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DBA for such rate class. DSM balance adjustment amounts will be assigned for recovery purposes to the rate classes for which over- or under-recoveries of DSM amounts were realized.

DCCR = DSM CAPITAL COST RECOVERY

The DCCR component is the means by which the Company recovers its capital investments made for DSM programs, as well as an approved rate of return on such capital investments. The Company calculates the DCCR component as follows:

$$DCCR = [(RB)\ (ROR + (ROR - DR)\ (TR / (1 - TR))] + OE$$

a) RB is the total rate base for DCCR projects.
b) ROR is the overall rate of return on DSM Rate Base (RB).
c) DR is the composite debt rate (i.e., the cost of short- and long-term debt) embedded in ROR.
d) TR is the composite federal and state income tax rate that applies to the equity return component of ROR.
e) OE is the sum of the capital-related operating expenses (i.e., depreciation and amortization expense, property taxes, and insurance expense) of the DSM projects to which DCCR applies.

The Company then allocates the DCCR component to the rate class(es) benefitting from the Company's various DSM-related capital investment(s).

CHANGES TO DSMRC

Modifications to other components of the DSMRC shall be made at least thirty days prior to the effective period for billing. Each filing shall include the following information as applicable:

1) A detailed description of each DSM program developed by the collaborative process, the total cost of each program over the twelve-month period, an analysis of expected resource savings, information concerning the specific DSM or efficiency measures to be installed, and any applicable studies that have been performed, as available.
2) A statement setting forth the detailed calculation of the DCR, DRLS, DSMI, DBA, DCCR, and DSMRC.

Each change in the DSMRC shall be placed into effect with bills rendered on and after the effective date of such change.

PROGRAMMATIC CUSTOMER CHARGES

Residential Customer Program Participation Incentives:
The following Demand Side Management programs are available to residential customers receiving service from the Company on the RS, VFD and LEV Standard Electric Rate Schedules.

Residential Load Management / Demand Conservation
The Residential Load Management / Demand Conservation Program employ switches in homes to help reduce the demand for electricity during peak times. The program communicates with the switches to cycle central air conditioning units, heat pumps, electric water heaters, and pool pumps off and on through a predetermined sequence. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

Residential Conservation / Home Energy Performance Program
The on-site audit offers a comprehensive audit from a certified auditor and incentives for residential customers to support the implementation of energy saving measures for a fee of $25. Customers are eligible for incentives of $500 or $1,000 based on customer purchased and installed energy efficiency measures and validated through a follow-up test.

Residential Low Income Weatherization Program (WeCare)

The Residential Low Income Weatherization Program (WeCare) is an education and weatherization program designed to reduce energy consumption of LG&E's low-income customers. The program provides energy audits, energy education, blower door tests, and installs weatherization and energy conservation measures. Qualified customers could receive energy conservation measures ranging from $0 to $2,100 based upon the customer's most recent twelve month energy usage and results of an energy audit.

Smart Energy Profile

The Smart Energy Profile Program provides a portion of KU's highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar properties in locality. The report will help the customer understand and make better informed choices as it relates to energy usage and the associated costs. Information presented in the report will include a comparison of the customer's energy usage to that of similar houses (collectively) and a comparison to the customer's own energy usage in the prior year.

Residential Incentives Program

The Residential Incentives Program encourages customers to purchase and install various ENERGY STAR® appliances, HVAC equipment, or window films that meet certain requirements, qualifying them for an incentive as noted in the table below.

Category	Item	Incentive
Appliances	Heat Pump Water Heaters (HPWH)	$300 per qualifying item purchased
	Washing Machine	$75 per qualifying item purchased
	Refrigerator	$100 per qualifying item purchased
	Freezer	$50 per qualifying item purchased
	Dishwasher	$50 per qualifying item purchased
Window Film	Window Film	Up to 50% of materials cost only; max of $200 per customer account; product must meet applicable criteria.
HVAC	Central Air Conditioner	$100 per Energy Star item purchased plus an additional $100 per SEER improvement above minimum
	Electric Air-Source Heat Pump	$100 per Energy Star item purchased plus additional $100 per SEER improvement above minimum

Residential Refrigerator Removal Program

The Residential Refrigerator Removal Program is designed to provide removal and recycling of working, inefficient secondary refrigerators and freezers from KU customer households. Customers participating in this program will be provided a one-time incentive. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

Residential High Efficiency Lighting Program

The Residential High Efficiency Lighting program promotes an increased use of ENERGY STAR® rated CFLs within the residential sector. The Residential High Efficiency Lighting Program distributes compact fluorescent bulbs through direct-mail.

Residential New Construction Program

The Residential New Construction program is designed to reduce residential energy usage and facilitate market transformation by creating a shift in builders' new home construction to include energy-efficient construction practices. Builders who are part of the program can take advantage of technical training classes, gain additional exposure to potential customers and receive incentives to help offset costs when including more energy-efficient features during home construction. KU will reimburse the cost of plan reviews and inspection costs related to an Energy Star or HERS home certification.

Residential HVAC Diagnostics and Tune Up Program

The Residential HVAC Diagnostic and Tune-up program targets customers with HVAC system performance issues. There are no incentives paid directly to customers. Customers are charged a discounted, fixed-fee for the diagnosis and if needed, a similar fee for implementation of corrective actions. Thus, the program pays the portion of diagnostic and tune-up cost in excess of the customer charge below. The customer cost is as follows:

- Customer cost is $35 per unit for diagnostics test
- Customer cost is $50 per unit for tune-up

Customer Education and Public Information

These programs help customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through two processes: a mass-media campaign and an elementary- and middle-school program. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts.

Dealer Referral Network

The Dealer Referral Network assists customers in identifying qualified service providers to install energy efficiency improvements recommended and/ or subsidized by the various energy efficiency programs.

Commercial Customer Program Participation Incentives:
The following Demand Side Management programs are available to commercial customers receiving service from the Company on the GS, AES, PS, TODS, and TODP Standard Electric Rate Schedules.

Commercial Load Management / Demand Conservation
The Commercial Load Management / Demand Conservation Program employ switches or interfaces to customer equipment, in small and large commercial businesses to help reduce the demand for electricity during peak times. The Program communicates with the switches or interface to cycle equipment. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

Commercial Conservation (Energy Audits) / Commercial Incentives
The Commercial Conservation / Commercial Inventive Program is designed to provide energy efficiency opportunities for the Companies' commercial class customers through energy audits and to increase the implementation of energy efficiency measures by providing financial incentives to assist with the replacement of aging and less efficient equipment. Incentives available to all commercial customers are based upon a $100 per kW removed for calculated efficiency improvements. A prescriptive list provides customers with incentive values for various efficiency improvements projects. Additionally, a custom rebate is available based upon company engineering validation of sustainable KW removed.

- Maximum annual incentive per facility is $50,000
- Customers can receive multi-year incentives in a single year where such multi-year incentives do not exceed the aggregate of $100,000 per facility and no incentive was provided in the immediately preceding year
- Applicable for combined Prescriptive and Custom Rebates

Commercial HVAC Diagnostics and Tune Up Program
The Commercial HVAC Diagnostic and Tune-up program targets customers with HVAC system performance issues. There are no incentives paid directly to customers. Customers are charged a discounted, fixed-fee for the diagnosis and if needed, a similar fee for implementation of corrective actions. Thus, the program pays the portion of diagnostic and tune-up cost in excess of the customer charge below. The customer cost is as follows:

- Customer cost is $50 per unit for diagnostics test
- Customer cost is $100 per unit for tune-up

Customer Education and Public Information
These programs help customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through two processes: a mass-media campaign and an elementary- and middle-school program. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and

innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts.

Dealer Referral Network
The Dealer Referral Network assists customers in identifying qualified service providers to install energy efficiency improvements recommended and/ or subsidized by the various energy efficiency programs.

Current Program Incentive Structures

Residential Load Management / Demand Conservation
Switch Option:
- $5/month bill credit for June, July, August, & September per air conditioning unit or heat pump on single family home.
- $2/month bill credit for June, July, August, & September per electric water heater or swimming pool pump on single family home.
- If new customer registers by May 31, 2012, then a $10 gift card per air-conditioning unit, heat pump, water-heater and/or swimming pool pump switch installed.
  - Customers in a tenant landlord relationship will receive the entire $10 new customer incentive.

Multi-family Option:
- $2/month bill credit per customer for June, July, August, & September.
- $2/month incentive per air conditioning or heat pump switch to the premise owner for June, July, August, & September.
- If new customer registers by May 31, 2012, then a $10 gift card per air-conditioning unit or heat pump installed.
  - Customers in a tenant landlord relationship where the entire complex participates will split the new customer incentive with the property owner.
  - Customers in a tenant landlord relationship where only a portion of the complex participates, the tenant will receive a $5 new customer incentive.

Residential Refrigerator Removal Program
The program provides $30 per working refrigerator or freezer.

Commercial Load Management / Demand Conservation
Switch Option
- $5 per month bill credit for June, July, August, & September for air conditioning units up to 5 tons. An additional $1 per month bill credit for each additional ton of air conditioning above 5 tons based upon unit rated capacity.

Customer Equipment Interface Option
The Company will offer a Load Management / Demand Response program tailored to a commercial customer's ability to reduce load. Program participants must commit to a minimum of 50KW demand reduction per control event. The Company will continue to enroll program participants until10MW curtailable load is achieved.
- $25 per KW for verified load reduction during June, July, August, & September.
- The customer will have access to at least hourly load data for every month of the year which they remain enrolled in the program.

- Additional customer charges may be incurred for metering equipment necessary for this program at costs under other tariffs.

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Residential Service Rate RS, Volunteer Fire Department Service Rate VFD, and Low Emission Vehicle Service Rate LEV	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00133 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00075 per kWh
DSM Incentive (DSMI)	$ 0.00006 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00049 per kWh
DSM Balance Adjustment (DBA)	$(0.00040) per kWh
Total DSMRC for Rates RS, VFD and LEV	$ 0.00223 per kWh

General Service Rate GS	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00065 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00085 per kWh
DSM Incentive (DSMI)	$ 0.00003 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00007 per kWh
DSM Balance Adjustment (DBA)	$(0.00006) per kWh
Total DSMRC for Rates GS	$ 0.00154 per kWh

All Electric School Rate AES	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00018 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00019 per kWh
DSM Incentive (DSMI)	$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per kWh
DSM Balance Adjustment (DBA)	$(0.00008) per kWh
Total DSMRC for Rate AES	$ 0.00030 per kWh

Commercial Customers Served Under Power Service Rate PS, Time of Day Secondary Service Rate TODS, and Time-of-Day Primary Service Rate TODP	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00020 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00026 per kWh
DSM Incentive (DSMI)	$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per kWh
DSM Balance Adjustment (DBA)	$ 0.00001 per kWh
Total DSMRC for Rates PS, TODS, and TODP	$ 0.00048 per kWh

Industrial Customers Served Under Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Rate RTS	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00000 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00000 per kWh
DSM Incentive (DSMI)	$ 0.00000 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per kWh
DSM Balance Adjustment (DBA)	$ 0.00000 per kWh
Total DSMRC for Rates PS, TODS, TODP, and RTS	$ 0.00000 per kWh

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except CTAC and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC and DSM Adjustment Clauses. Standard Electric Rate Schedules subject to this schedule are divided into Group 1 or Group 2 as follows:

Group 1: Rate Schedules RS; VFD; AES; LS; RLS; LE; TE; and Pilot Program LEV. T
Group 2: Rate Schedules GS; PS; TODS; TODP; RTS; and FLS.

T

RATE

The monthly billing amount under each of the schedules to which this mechanism is applicable, shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

Group Environmental Surcharge Billing Factor = Group E(m) / Group R(m)

As set forth below, Group E(m) is the sum of Jurisdictional E(m) of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the 12-month average revenue for the current expense month and for Group 2 it is the 12-month average non-fuel revenue for the current expense month.

DEFINITIONS

1) For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – EAS + BR T
   a) RB is the Total Environmental Compliance Rate Base.
   b) ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the overall rate of return [cost of short-term debt, long-term debt, preferred stock, and common equity].
   c) DR is the Debt Rate [cost of short-term debt, and long-term debt].
   d) TR is the Composite Federal and State Income Tax Rate.
   e) OE is the Operating Expenses. OE includes operation and maintenance expense recovery authorized by the K.P.S.C. in all approved ECR Plan proceedings. T
   f) EAS is the total proceeds from emission allowance sales applicable to the pre-2011 Plans only. T
   g) BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse applicable to the pre-2011 Plans only.
   h) Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183.

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor. Jurisdictional E(m) is adjusted for any (Over)/Under collection or prior period adjustment and by the subtraction of the Revenue Collected through Base Rates for the Current Expense month to arrive at Adjusted Net Jurisdictional E(m). Adjusted Net Jurisdictional E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the 12 months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).

3) The Group 1 R(m) is the average of total Group 1 monthly base revenue for the 12 months ending with the current expense month. Base revenue includes the customer, energy, and lighting charges for each rate schedule included in Group 1 to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.

4) The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the 12 months ending with the current expense month. Base non-fuel revenue includes the customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this mechanism is applicable and automatic adjustment clause revenues for the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6.

5) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

Adjustment Clause **FF**

Franchise Fee Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available as an option for collection of revenues within governmental jurisdictions which impose on Company franchise fees, permitting fees, local taxes or other charges by ordinance, franchise, or other governmental directive and not otherwise collected in the charges of Company's base rate schedules.

DEFINITIONS

Base Year - the twelve month period ending November 30.
Collection Year - the full calendar year following the Base Year.
Base Year Amount -

1) a percentage of revenues, as determined in the franchise agreement, for the Base Year; and
2) license fees, permit fees, or other costs specifically borne by Company for the purpose of maintaining the franchise as incurred in the Base Year and applicable specifically to Company by ordinance or franchise for operation and maintenance of its facilities in the franchise area, including but not limited to costs incurred by Company as a result of governmental regulation or directives requiring construction or installation of facilities beyond that normally provided by Company in accordance with applicable Rules and Regulations approved by and under the direction of the Kentucky Public Service Commission; and
3) any adjustment for over or under collection of revenues associated with the amounts in 1) or 2).

RATE

The franchise percentage will be calculated by dividing the Base Year amount by the total revenues in the Base Year for the franchise area. The franchise percentage will be monitored during the Collection Year and adjusted to recover the Base Year Amount in the Collection Year as closely as possible.

BILLING

1) The franchise charge will be applied exclusively to the base rate and all riders of bills of customers receiving service within the franchising governmental jurisdiction, before taxes.
2) The franchise charge will appear as a separate line item on the Customer's bill and show the unit of government requiring the franchise.
3) Payment of the collected franchise charges will be made to the governmental franchising body as agreed to in the franchise agreement.

TERM OF CONTRACT

As agreed to in the franchise agreement. In the event such franchise agreement should lapse but payment of franchise fees, other local taxes, or permitting fees paid by Company by ordinance, franchise, or other governmental directive should continue, collection shall continue under this tariff.

TERMS AND CONDITIONS

Service will be furnished in accordance with the provisions of the franchise agreement in so far as those provisions do not conflict with the Terms and Conditions applicable to Company approved by and under the direction of the Kentucky Public Service Commission.

Adjustment Clause **ST**
School Tax

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is applied as a rate increase to all other schedules pursuant to KRS 160.617 for the recovery by the utility of school taxes in any county requiring a utility gross receipts license tax for schools under KRS 160.613.

RATE

The utility gross receipts license tax authorized under state law.

Adjustment Clause **HEA**
Home Energy Assistance Program

APPLICABLE
In all territory served.

AVAILABILITY
To all residential customers.

RATE
$0.16 per meter per month.

BILLING
The HEA charge shall be shown as a separate item on customer bills.

SERVICE PERIOD
The Home Energy Assistance charge will be applied to all residential electric bills rendered during the billing cycles commencing October 1, 2007 through September 30, 2015, or as otherwise directed by the Public Service Commission. Proceeds from this charge will be used to fund residential low-income demand-side management Home Energy Assistance programs which have been designed through a collaborative advisory process and then filed with, and approved by, the Commission.

TERMS AND CONDITIONS

Customer Bill of Rights

As a residential customer of a regulated public utility in Kentucky, you are guaranteed the following rights subject to Kentucky Revised Statutes and the provisions of the Kentucky Public Service Commission Administrative Regulations:

- You have the right to service, provided you (or a member of your household whose debt was accumulated at your address) are not indebted to the utility.
- You have the right to inspect and review the utility's rates and tariffed operating procedures during the utility's normal office hours.
- You have the right to be present at any routine utility inspection of your service conditions.
- You must be provided a separate, distinct disconnect notice alerting you to a possible disconnection of your service, if payment is not received.
- You have the right to dispute the reasons for any announced termination of your service.
- You have the right to negotiate a partial payment plan when your service is threatened by disconnection for non-payment.
- You have the right to participate in equal, budget payment plans for your natural gas and electric service.
- You have the right to maintain your utility service for up to thirty (30) days upon presentation of a medical certificate issued by a health official.
- You have the right to prompt (within 24 hours) restoration of your service when the cause for discontinuance has been corrected.
- If you have not been disconnected, you have the right to maintain your natural gas and electric service for up to thirty (30) days, provided you present a Certificate of Need issued by the Kentucky Cabinet for Human Resources between the months of November and the end of March.
- If you have been disconnected due to non-payment, you have the right to have your natural gas or electric service reconnected between the months of November through March provided you:
  1) Present a Certificate of Need issued by the Kentucky Cabinet for Human Resources, and
  2) Pay one third (1/3) of your outstanding bill ($200 maximum), and
  3) Accept referral to the Human Resources' Weatherization Program, and
  4) Agree to a repayment schedule that will cause your bill to become current by October 15.
- You have the right to contact the Public Service Commission regarding any dispute that you have been unable to resolve with your utility (call Toll Free 1-800-772-4636).

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

All electric service supplied by Company shall be in accordance with the applicable rules and regulations of the Public Service Commission of Kentucky.

COMPANY TERMS AND CONDITIONS

In addition to the rules and regulations of the Commission, all electric service supplied by Company shall be in accordance with these Terms and Conditions, which shall constitute a part of all applications and contracts for service.

RATES, TERMS AND CONDITIONS ON FILE

A copy of the rate schedules, terms, and conditions under which electric service is supplied is on file with the Public Service Commission of Kentucky. A copy of such rate schedules, terms and conditions, together with the law, rules, and regulations of the Commission, is available for public inspection in each office of Company where bills may be paid.

ASSIGNMENT

No order for service, agreement or contract for service may be assigned or transferred without the written consent of Company.

RENEWAL OF CONTRACT

If, upon the expiration of any service contract for a specified term, the customer continues to use the service, the contract (unless otherwise provided therein) will be automatically renewed for successive periods of one (1) year each, subject to termination at the end of any year upon thirty (30) days prior written notice by either party.

AGENTS CANNOT MODIFY AGREEMENT WITHOUT CONSENT OF P.S.C. OF KY.

No agent has power to amend, modify, alter, or waive any of these Terms and Conditions, or to bind Company by making any promises or representations not contained herein.

SUPERSEDE PREVIOUS TERMS AND CONDITIONS

These Terms and Conditions supersede all terms and conditions under which Company has previously supplied electric service.

TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

A written application or contract, properly executed, may be required before Company is obligated to render electric service. Company shall have the right to reject for valid reasons any such application or contract.

All applications for service shall be made in the legal name of the party desiring the service.

Where an unusual expenditure for construction or equipment is necessary or where the proposed manner of using electric service is clearly outside the scope of Company's standard rate schedules, Company may establish special contracts giving effect to such unusual circumstances. Customer accepts that non-standard service may result in the delay of required maintenance or, in the case of outages, restoration of service.

TRANSFER OF APPLICATION

Applications for electric service are not transferable and new occupants of premises will be required to make application for service before commencing the use of electricity. Customers who have been receiving electric service shall notify Company when discontinuance of service is desired, and shall pay for all electric service furnished until such notice has been given and final meter readings made by Company.

CONTRACTED DEMANDS

For rate applications where billing demand minimums are determined by the Contract Demand customer shall execute written Contract prior to rendering of service. At Company’s sole discretion, in lieu of a written contract, a completed load data sheet or other written load specification, as provided by Customer, can be used to determine the maximum load on Company’s system for determining Contract Demand minimum.

OPTIONAL RATES

If two or more rate schedules are available for the same class of service, it is Customer’s responsibility to determine the options available and to designate the schedule under which customer desires to receive service.

Company will, at any time, upon request, advise any customer as to the most advantageous rate for existing or anticipated service requirements as defined by the customer, but Company does not assume responsibility for the selection of such rate or for the continuance of the lowest annual cost under the rate selected.

In those cases in which the most favorable rate is difficult to predetermine, Customer will be given the opportunity to change to another schedule, unless otherwise prevented by the rate schedule under which Customer is currently served, after trial of the schedule originally designated; however, after the first such change, Company shall not be required to make a change in schedule more often than once in twelve (12) months.

TERMS AND CONDITIONS

Customer Responsibilities

From time to time, Customer should investigate Customer's operating conditions to determine a desirable change from one available rate to another. Company, lacking knowledge of changes that may occur at any time in Customer's operating conditions, does not assume responsibility that Customer will at all times be served under the most beneficial rate.

In no event will Company make refunds covering the difference between the charges under the rate in effect and those under any other rate applicable to the same class of service.

CUSTOMER'S EQUIPMENT AND INSTALLATION

Customer shall furnish, install, and maintain at Customer's expense all electrical apparatus and wiring to connect with Company's service drop or service line. All such apparatus and wiring shall be installed and maintained in conformity with applicable statutes, laws or ordinances and with the rules and regulations of the constituted authorities having jurisdiction. Customer shall not install wiring or connect and use any motor or other electricity-using device which in the opinion of Company is detrimental to its electric system or to the service of other customers of Company. Company assumes no responsibility whatsoever for the condition of Customer's electrical wiring, apparatus, or appliances, nor for the maintenance or removal of any portion thereof.

In the event Customer builds or extends its own transmission or distribution system over property Customer owns, controls, or has rights to, and said system extends or may extend into the service territory of another utility company, Customer will notify Company of their intention in advance of the commencement of construction.

OWNER'S CONSENT TO OCCUPY

Customer shall grant easements and rights-of-way on and across Customer's property at no cost to Company.

ACCESS TO PREMISES AND EQUIPMENT

Company shall have the right of access to Customer's premises at all reasonable times for the purpose of installing, meter reading, inspecting, repairing, or removing its equipment used in connection with its supply of electric service or for the purpose of turning on and shutting off the supply of electricity when necessary and for all other proper purposes. Customer shall not construct or permit the construction of any structure or device which will restrict the access of Company to its equipment for any of the above purposes.

PROTECTION OF COMPANY'S PROPERTY

Customers will be held responsible for tampering, interfering with, breaking of seals of meters, or other equipment of Company installed on Customer's premises, and will be held liable for same according to law. Customer hereby agrees that no one except the employees of Company shall be allowed to make any internal or external adjustments of any meter or any other piece of apparatus which shall be the property of Company.

TERMS AND CONDITIONS

Customer Responsibilities

POWER FACTOR

Company installs facilities to supply power to Customer at or near unity power factor.

Company expects any customer to use apparatus which shall result in a power factor near unity. However, Company will permit the use of apparatus which shall result, during normal operation, in a power factor not lower than 90 percent either lagging or leading.

Where Customer’s power factor is less than 90 percent, Company reserves the right to require Customer to furnish, at Customer’s own expense, suitable corrective equipment to maintain a power factor of 90 percent or higher.

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

Except in cases where Customer has a contract with Company for reserve or auxiliary service, no other electric light or power service will be used by Customer on the same installation in conjunction with Company's service, either by means of a throw-over switch or any other connection.

LIABILITY

Customer assumes all responsibility for the electric service upon Customer's premises at and from the point of delivery of electricity and for the wires and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of electricity, occasioned by such electricity or said wires and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence of Company.

NOTICE TO COMPANY OF CHANGES IN CUSTOMER’S LOAD

The service connections, transformers, meters, and appurtenances supplied by Company for the rendition of electric service to its customers have a definite capacity which may not be exceeded without damage. In the event that Customer contemplates any material increase in Customer’s connected load, whether in a single increment or over an extended period, Customer shall immediately give Company written notice of this fact so as to enable it to enlarge the capacity of such equipment. In case of failure to give such notice Customer may be held liable for any damage done to meters, transformers, or other equipment of Company caused by such material increase in Customer's connected load. Should Customer make a permanent change in the operation of electrical equipment that materially reduces the maximum load required by Customer, Company may reduce Customer’s contract capacity.

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TERMS AND CONDITIONS

Customer Responsibilities

PERMITS

Customer shall obtain or cause to be obtained all permits, easements, or certificates, except street permits, necessary to give Company or its agents access to Customer's premises and equipment and to enable its service to be connected therewith. In case Customer is not the owner of the premises or of intervening property between the premises and Company's distribution lines the customer shall obtain from the proper owner or owners the necessary consent to the installation and maintenance in said premises and in or about such intervening property of all such wiring or other customer-owned electrical equipment as may be necessary or convenient for the supply of electric service to customer. Provided, however, to the extent permits, easements, or certificates are necessary for the installation and maintenance of Company-owned facilities, Company shall obtain the aforementioned consent. T

The construction of electric facilities to provide service to a number of customers in a manner consistent with good engineering practice and the least public inconvenience sometimes requires that certain wires, guys, poles, or other appurtenances on a customer's premises be used to supply service to neighboring customers. Accordingly, each customer taking Company's electric service shall grant to Company such rights on or across his or her premises as may be necessary to furnish service to neighboring premises, such rights to be exercised by Company in a reasonable manner and with due regard for the convenience of Customer.

Company shall make or cause to be made application for any necessary street permits, and shall not be required to supply service under Customer's application until a reasonable time after such permits are granted.

TERMS AND CONDITIONS

Company Responsibilities

METERING

The electricity used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

POINT OF DELIVERY OF ELECTRICITY

The point of delivery of electrical energy supplied by Company shall be at the point, as designated by Company, where Company's facilities are connected with the facilities of Customer, irrespective of the location of the meter.

EXTENSION OF SERVICE

The main transmission lines of Company, or branches thereof, will be extended to such points as provide sufficient load to justify such extensions or in lieu of sufficient load, Company may require such definite and written guarantees from a customer, or group of customers, in addition to any minimum payments required by the Tariff as may be necessary. This requirement may also be made covering the repayment, within a reasonable time, of the cost of tapping such existing lines for light or power service or both.

COMPANY'S EQUIPMENT AND INSTALLATION

Company will furnish, install, and maintain at its expense the necessary overhead service drop or service line required to deliver electricity at the voltage contracted for, to Customer's electric facilities.

Company will furnish, install, and maintain at its expense the necessary meter or meters. (The term meter as used here and elsewhere in these rules and regulations shall be considered to include all associated instruments and devices, such as current and potential transformers installed for the purpose of measuring deliveries of electricity to the customer.) Suitable provision for Company's meter, including an adequate protective enclosure for the same if required, shall be made by Customer. Title to the meter shall remain in Company, with the right to install, operate, maintain, and remove same. Customer shall protect such property of Company from loss or damage, and no one who is not an agent of Company shall be permitted to remove, damage, or tamper with the same. Customer shall execute such reasonable form of easement agreement as may be required by Company.

Notwithstanding the provisions of 807 KAR 5:006, Section 13(4), a reasonable time shall be allowed subsequent to Customer's service application to enable Company to construct or install the facilities required for such service. In order that Company may make suitable provision for enlargement, extension or alteration of its facilities, each applicant for commercial or industrial service shall furnish Company with realistic estimates of prospective electricity requirements.

TERMS AND CONDITIONS

Company Responsibilities

COMPANY NOT LIABLE FOR INTERRUPTIONS

Company will exercise reasonable care and diligence in an endeavor to supply service continuously and without interruption but does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay or failure of electric service not caused by the willful negligence of Company, or resulting from any cause or circumstance beyond the reasonable control of Company.

COMPANY NOT LIABLE FOR DAMAGE ON CUSTOMER'S PREMISES

Company is merely a supplier of electricity delivered to the point of connection of Company's and Customer's facilities, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or property of Customer or of third persons resulting from the presence, use or abuse of electricity on Customer's premises or resulting from defects in or accidents to any of Customer's wiring, equipment, apparatus, or appliances, or resulting from any cause whatsoever other than the negligence of Company

LIABILITY

In no event shall Company have any liability to Customer or any other party affected by the electrical service to Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to Customer or any other party. In the event that the customer's use of Company's service causes damage to Company's property or injuries to persons, Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

FIRM SERVICE

Where a customer-generator supplies all or part of the customer-generator's own load and desires Company to provide supplemental or standby service for that load, the customer-generator must contract for such service under Company's Supplemental or Standby Service Rider, otherwise Company has no obligation to supply the non-firm service. This requirement does not apply to Net Metering Service (Rider NMS). T

TERMS AND CONDITIONS

Character of Service

Electric service, under the rate schedules herein, will be 60 cycle, alternating current delivered from Company's various load centers and distribution lines at typical nominal voltages and phases, as available in a given location, as follows:

SECONDARY VOLTAGES

Residential Service -

Single phase 120/240 volts three-wire service or 120/208Y volts three-wire service where network system is available.

Non-Residential Service -

1) Single phase 120/240 volts three-wire service, or 120/208Y volts three-wire service where network system is available.
2) Three phase 240 volts three-wire service, 120/240 volts four-wire service, 480 volts three-wire service, 120-208Y volts four-wire service, or 277/480Y four-wire service.

PRIMARY VOLTAGES

According to location, 2,400/4160Y volts, 7,200/12,470Y volts, or 34,500 volts

TRANSMISSION VOLTAGES

According to location, 69,000 volts, 138,000 volts, or 345,000 volts.

The voltage available to any individual customer shall depend upon the voltage of Company's lines serving the area in which Customer's electric load is located.

RESTRICTIONS

1. Except for minor loads, with approval of company, two-wire service is restricted to those customers on service July 1, 2004.
2. To be eligible for the rate applicable to any delivery voltage other than secondary voltage, Customer must furnish and maintain complete substation structure, transformers, and other equipment necessary to take service at the primary or transmission voltage available at point of connection.
   a) In the event Company is required to provide transformation to reduce an available voltage to a lower voltage for delivery to a customer, Customer shall be served at the rate applicable to the lower voltage; provided, however, that if the same rate is applicable to both the available voltage and the delivery voltage, Customer may be required to make a non-refundable payment to reflect the additional investment required to provide service.
   b) The available voltage shall be the voltage on that distribution or transmission line which Company designates as being suitable from the standpoint of capacity and other operating characteristics for supplying the requirements of Customer.

Date of Issue: June 29, 2012
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

Residential electric service is available for uses customarily associated with residential occupation, including lighting, cooking, heating, cooling, refrigeration, household appliances, and other domestic purposes.

1. Residential rates are based on service to single family units and are not applicable to multi-family dwellings served through a single meter. Where two or more families occupy a residential building, Company will require, as a condition precedent to the application of the residential rate, that the wiring in the building be so arranged as to permit each family to be served through a separate meter. In those cases where such segregation of wiring would involve undue expense to Customer, Company will allow service to two or more families to be taken through one meter, but in this event the minimum bills of the applicable residential rate shall be multiplied by the number of families thus served, such number of families to be determined on the basis of the number of kitchens in the building. At Customer's option, in lieu of the foregoing, electric service rendered to a multi-family residential building through a single meter will be classified as commercial and billed on the basis of service to one customer at an appropriate non-residential rate.

2. Single family unit service shall include usage of electric energy customarily incidental to home occupations, such as the office of a physician, surgeon, dentist, musician or artist when such occupation is carried on by Customer in his residence.

3. A residential building used by a single family as a home, which is also used to accommodate roomers or boarders for compensation, will be billed at the residential rate provided it does not exceed twelve (12) rooms in size. Such a residential building of more than twelve (12) rooms used to accommodate roomers or borders for compensation will be classified as commercial and billed on the appropriate rate. In determining the room rating of rooming and boarding houses, all wired rooms shall be counted except hallways, vestibules, alcoves, closets, bathrooms, lavatories, garrets, attics, storage rooms, trunk rooms, basements, cellars, porches and private garages.

4. Service used in residential buildings occupied by fraternity or sorority organizations associated with educational institutions will be classified as residential and billed at the residential rate.

5. Where both residential and general or commercial classes of service are supplied through a single meter, such combined service shall be billed at the appropriate non-residential rate. Customer may arrange his wiring so as to separate the general service from the residential service, in which event two meters will be installed by Company and separate residential and general service rates applied to the respective classes of service.

6. If Customer's barns, pump house or other outbuildings are located at such distance from his residence as to make it impracticable to supply service thereto through his residential meter, the separate meter required to measure service to such remotely located buildings will be considered a separate service contract and billed as a separate customer on the applicable non-residential rate.

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

7. Single-phase power service used for domestic purposes will be permitted under Residential Rate RS when measured through the residential meter subject to the conditions set forth below:

   (a) Single-phase motors may be served at 120 volts if the locked-rotor current at rated voltage does not exceed 50 amperes. Motors with locked-rotor current ratings in excess of 50 amperes must be served at 240 volts.

   (b) Single-phase motors of new central residential cooling installations with total locked-rotor ratings of not to exceed 125 amperes (inclusive of any auxiliary motors arranged for simultaneous starting with the compressor) may be connected for across-the-line starting provided the available capacity of Company's electric distribution facilities at desired point of supply is such that, in Company's judgment, the starting of such motors will not result in excessive voltage dips and undue disturbance of lighting service and television reception of nearby electric customers. However, except with Company's express written consent, no new single-phase central residential cooling unit having a total lock-rotor rating in excess of 125 amperes inclusive of auxiliary motors arranged for simultaneous starting with the compressor) shall hereafter be connected to Company's lines, or be eligible for electric service therefrom, unless it is equipped with an approved type of current-limiting device for starting which will reduce the initial and incremental starting current inrush to a maximum of 100 amperes per step. Company shall be furnished with reasonable advance notice of any proposed central residential cooling installation.

   (c) In the case of multi-motored devices arranged for sequential starting of the motors, the above rules are considered to apply to the locked-rotor currents of the individual motors; if arranged for simultaneous starting of the motors, the rules apply to the sum of the locked-rotor currents of all motors so started.

   (d) Any motor or motors served through a separate meter will be billed as a separate customer.

TERMS AND CONDITIONS

BILLING

METER READINGS AND BILLS

Each bill for utility service shall be issued in compliance with 807 KAR 5:006, Section 6.

All bills will be based upon meter readings made in accordance with Company's meter reading schedule. Company, except if prevented by reasons beyond its control, shall read customers meters at least quarterly, except that customer-read meters shall be read at least once during the calendar year.

In the case of opening and closing bills when the total period between regular and special meter readings is less than thirty days, the minimum charges of the applicable rate schedules will be prorated on the basis of the ratio of the actual number of days in such period to thirty days.

When Company is unable to read Customer's meter after reasonable effort, or when Company experiences circumstances which make actual meter readings impossible or impracticable, Customer may be billed on an estimated basis and the billing will be adjusted as necessary when the meter is read.

In the event Company's meter fails to register properly by reason of damage, accident, etc., Company shall have the right to estimate Customer's consumption during the period of failure on the basis of such factors as Customer's connected load, heating degree days, and consumption during a previous corresponding period and during a test period immediately following replacement of the defective meter.

Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within twelve (12) calendar days from date of rendition thereof. If full payment is not received within three (3) calendar days after the due date of the bill, a late payment charge will be assessed on the current month’s charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice. There will be no adverse credit impact on the customer’s payment and credit record, including credit scoring, both internally and externally, and the account will not be considered delinquent for any purpose if the Company receives the customer’s payment within fifteen days after the date on which the Company issues the customer’s bill.

Failure to receive a bill does not exempt Customer from these provisions of Company’s Terms and Conditions.

READING OF SEPARATE METERS NOT COMBINED

For billing purposes, each meter upon Customer's premises will be considered separately and readings of two (2) or more meters will not be combined except where Company's operating convenience requires the installation of two (2) or more meters upon Customer's premises instead of one (1) meter.

TERMS AND CONDITIONS

BILLING

CUSTOMER RATE ASSIGNMENT

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If Customer takes service under a rate schedule the eligibility for which contains a minimum or maximum demand parameter (or both), Company will review Customer's demand and usage data at least once annually to determine the rate schedule under which Customer will take service until the next review and rate determination. Company will also conduct such a review and determination upon Customer's request. Company shall not be obligated to change Customer's rate determination based upon detection of a substantial deviation of Customer's demand or usage if, after consultation with Customer, Company determines in its sole discretion that such deviation is not indicative of Customer's likely long-term demand. Similarly, Company may assign Customer to a rate schedule for which Customer would not be eligible based solely on Customer's historical demand or usage, but Company may do so only as part of a review and rate determination that involves consulting with Customer about Customer's likely future demand, as well as Customer's special contract demand, if applicable.

Any such review and rate determination shall be deemed conclusively to be the correct rate determination for Customer for all purposes and for all periods until Company conducts the next such review and determination for Customer. Therefore, Company shall not be liable for any refunds to Customer based upon Customer's rate assignment, and Company shall not seek to back-bill Customer based upon Customer's rate assignment, for any periods between and including such reviews and determinations unless, and only in the event that, a particular review and rate determination are shown to have been materially erroneous at the time they were conducted, in which case Company may be liable for a refund, or may back-bill Customer, only for the period from the erroneous review and determination to the present or the next non-erroneous review and determination, whichever is shorter.

If Company determines during a review as described above that Customer is eligible to take service under more than one rate schedule and that Customer is then taking service under such a rate schedule, Company will not change Customer's rate assignment; it will remain Customer's responsibility to choose between optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1.

If Company determines during a review as described above that Customer is eligible to take service under more than one rate schedule and that Customer is not then taking service under such a rate schedule, Company will (1) provide reasonable notice to Customer of the options available and (2) assign Customer to the rate schedule Company reasonably believes will be most financially beneficial to Customer based on Customer's historical demand and usage, which assignment Company will change upon Customer's request to take service under another rate schedule for which Customer is eligible. Company shall have no refund obligation or bear any other liability or responsibility for its initial assignment of Customer to a rate for which Customer is eligible; it is at all times Customer's responsibility to choose between optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

TERMS AND CONDITIONS

BILLING

Nothing in this section is intended to curtail or diminish Customer's responsibility to choose among optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1. Likewise, except as explicitly stated in the paragraph above, nothing in this section creates an obligation or responsibility for Company to assign Customer to a particular rate schedule for which Customer is eligible if Customer is eligible for more than one rate schedule. T

CUSTOMER RATE MIGRATION

A change from one rate to another will be effective with the first full billing period following a customer's request for such change, or with a rate change mandated by changes in a customer's load. In cases where a change from one rate to another necessitates a change in metering, the change from one rate to another will be effective with the first full billing period following the meter change.

CLASSIFICATION OF CUSTOMERS

For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are primarily engaged in a process or processes which create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32 and 33. All other non-residential customers will be defined as "commercial."

MONITORING OF CUSTOMER USAGE

In order to detect unusual deviations in individual customer consumption, Company will monitor the usage of each customer at least once annually. In addition, Company may investigate usage deviations brought to its attention as a result of its ongoing meter reading or billing processor customer inquiry. Should an unusual deviation in Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of Customer's meter reading and billing records, Company may contact Customer to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether it shows an average error greater than two (2) percent fast or slow. Company will notify Customer of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 10(4) and (5).

RESALE OF ELECTRIC ENERGY

Electric energy furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such energy to any other person, firm, or corporation on the Customer's premises, or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company's billing.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

TERMS AND CONDITIONS

BILLING

MINIMUM CHARGE

Without limiting the foregoing, the Demand Charge shall be due regardless of any event or occurrence that might limit (a) Customer's ability or interest in operating Customer's facility, including, but without limitation, any acts of God, fires, floods, earthquakes, acts of government, terrorism, severe weather, riot, embargo, changes in law, or strikes or (b) Company's ability to serve customer. T

TERMS AND CONDITIONS

Deposits

GENERAL

1) Company may require a cash deposit or other guaranty from customers to secure payment of bills in accordance with 807 KAR 5:006, Section 7, except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection.
2) Deposits may be required from all customers not meeting satisfactory credit and payment criteria. Satisfactory credit for customers will be determined by utilizing independent credit sources (primarily utilized with new customers having no prior history with Company), as well as historic and ongoing payment and credit history with Company.
   a) Examples of independent credit scoring resources include credit scoring services, public record financial information, financial scoring and modeling services, and information provided by independent credit/financial watch services.
   b) Satisfactory payment criteria with Company may be established by paying all bills rendered, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments, having no meter diversion or theft of service.
3) Company may offer residential or general service customers the option of paying all or a portion of their deposits in installments over a period not to exceed the first four (4) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.

RESIDENTIAL

1) Residential customers are those customers served under Residential Service, Sheet No. 5.
2) The deposit for a residential customer is in the amount of $135.00, which is calculated in accordance with 807 KAR 5:006, Section 7(1)(b).
3) Company will retain Customer’s deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.
4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise become a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

Date of Issue: June 29, 2012
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

TERMS AND CONDITIONS

Deposits

GENERAL SERVICE

1) General service customers are those customers served under General Service, Sheet No. 10.
2) The deposit for a general service customer is in the amount of $220.00, which is calculated in accordance with 807 KAR 5:006, Section 7(1)(b). The deposit for a General Service customer may be waived when the General Service delivery is to a detached building used in conjunction with a Residential Service and the General Service usage is no more than 300 kWh per month. T T T T
3) Company shall retain Customer's deposit as long as Customer remains on service.
4) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten (10%) percent, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

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OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential or general service, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR 5:006, Section 7(1)(a).
2) For customers not meeting the parameters of GENERAL SERVICE ¶ 2, above, Company may retain Customer's deposit as long as Customer remains on service.
3) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten (10%) percent, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise become a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to any residential customer or general service customer. Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in this plan at any time.

The budgeted amount will be determined by Company and will be based on one-twelfth of Customer's usage for either an actual or estimated twelve (12) months. The budgeted amount will be subject to review and adjustment by Company at any time during Customer's budget year. If actual usage indicates Customer's account will not be current with the final payment in Customer's budget year, Customer will be required to pay their Budget Payment Plan account to $0 prior to the beginning of the customer's next budget year.

If a customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove the customer from the plan, restore the customer to regular billing, and require immediate payment of any deficiency. A customer removed from the Budget Payment Plan for non-payment may be prohibited from further participation in the plan for twelve (12) months.

Failure to receive a bill in no way exempts a customer from the provisions of these terms and conditions.

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TERMS AND CONDITIONS

Bill Format

KU. a PPL company

Customer Service: 1-800-331-7370 (M-F, 7a.m.to 7 p.m ET)
Telephone Payments: 1-800-331-7370; press 1-2-2-3 (24 hours a day; $2.95 fee)
Walk-In Center Hours: Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service: www.lge-ku.com (24 hours a day)

DATE DUE	AMOUNT DUE
04/23/12	$65.85

Late Payment Fees will be applied to current charges if the current amount due is not received in full by the payment due date on this bill even if payment arrangements have been made. Please have your account number available when calling to discuss your account.

ACCOUNT INFORMATION

Account Number:	3000-0216-5900
Account Name:	JOHN DOE
Service Address:	1234 ANYWHERE ST
Next Read Will Occur:	05/03/12 - 05/07/12
Date Bill Mailed:	04/04/12 (Meter Read Portion 04)

Averages for Billing Period	This Year	Last Year
Average Temperature	60 °	49 °
Number of Days Billed	29	30
Electric/kwh per Day	24.7	28.3

BILLING SUMMARY

Previous Balance		12.26
Payments as of 3/6 - 4/3		(12.26)
Balance as of 4/3		0.00
Electric Charges	62.13	
Taxes and Fees	3.72	
Utility Charges as of 4/3		65.85
Total Amount Due		65.85

ELECTRIC CHARGES

Rate Type: Residential Service

Basic Service Charge	8.50
Energy Charge ($0.06987 x 717.00 kwh)	50.10
Electric DSM ($0.00223 x 717.00 kwh)	1.60
Fuel Adjustment ($.00054 x 717 kwh)	0.39
Environmental Surcharge (2.280% x $60.59)	1.38
Home Energy Assistance Fund Charge	0.16
Total Electric Charges	**$62.13**

Meter Reading Information

Meter # #12345	
Actual Reading on 4/3/12	6938
Previous Reading on 3/5/12	6221
Current kwh Usage	717
Meter Multiplier	1
Metered kwh Usage	717

TAXES AND FEES

Rate Increase For School Tax (3.00% x $61.97)	1.86
Franchise Fee-Lexington (3.00% x $61.97)	1.86
Total Taxes and Fees	**$3.72**

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date	$3.29

Please see reverse side for additional charges. Bring entire bill when paying in person.

Customer Service (800) 981-0600 **PLEASE RETURN THIS PORTION WITH YOUR PAYMENT**

Account Number	Payment Due Date	Amount Due by Due Date	Amount Due 3 Days After Due Date	Winter Care Donation	Amount Enclosed
3000-0216-5900	04/23/12	$65.85	$69.14	$	$

OFFICE USE ONLY:
MRU1081170, G000000
P23.07
PF:Y eB:P

☐ Check here if plan(s) requested on back of stub.

KU.
PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900062 4#
JOHN DOE
1234 Anywhere St
Lexington, KY KY 40026-9745

Service Address: 1234 Anywhere St

020000000000000000000000124560000001189500000000000000

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

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TERMS AND CONDITIONS

Bill Format

Account Number 3000-0216-5900 Page 2

IMPORTANT INFORMATION

The power to save. It's in your hands. The amount of electricity you consumed during this billing cycle resulted in the production of approximately 1,434 pounds of CO2 (carbon). A typical residential customer uses 1,000 kilowatt hours of electricity per month, which would result in the production of 2,000 lbs. of carbon. Visit our Web site at www.lge-ku.com for Smart Saver tips designed to help you better manage and lessen the environmental impact of your engery usage.

For a copy of your rate schedule, visit www.lge-ku.com or call our Customer Service Department.

If you use mail to submit your payment, please update your records to reflect the new address (located on the front of the bill) stub) for our payment processing center. Remember, you can pay your bill on line when you sign in or register your account at my.lge-ku.com.

New enrollment only - **Please check box(es) below and on front of stub.**

☐ Budget Plan

☐ I would like to enroll in Demand Conservation

☐ Auto Pay (voided check must be provided). *Please note that any past due balance on your LG&E account will be debited from your bank account immediately upon enrollment in the Auto Pay program. To avoid unintended debits to your bank account, please make sure your LG&E account balance is current before enrolling in Auto Pay.*

Please deduct my Auto Pay Payment from my Checking Account.
I hereby authorize KU to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future KU accounts, and will remain in effect until revoked by me or KU.

Signature: ____

Date: ______________________________

Processing Auto Pay requests can take up to two billing cycles. Please continue making regular payments until you receive a bill that indicates the amount due will be deducted from your bank account on the payment due date.

Signature: ____

Date: _________________________________

TERMS AND CONDITIONS

Discontinuance of Service

In accordance with and subject to the rules and regulations of the Public Service Commission of Kentucky, Company shall have the right to refuse or discontinue service to an applicant or customer under the following conditions:

A. When Company's or Commission's rules and regulations have not been complied with. However, service may be discontinued or refused only after Company has made a reasonable effort to induce Customer to comply with its rules and then only after Customer has been given at least ten (10) days written notice of such intention, mailed to his last known address.

B. When a dangerous condition is found to exist on Customer's or applicant's premises. In such case service will be discontinued without notice or refused, as the case might be. Company will notify Customer or applicant immediately of the reason for the discontinuance or refusal and the corrective action to be taken before service can be restored or initiated.

C. When Customer or applicant refuses or neglects to provide reasonable access and/or easements to and on his premises for the purposes of installation, operation, meter reading, maintenance, or removal of Company's property. Customer shall be given fifteen (15) days written notice of Company's intention to discontinue or refuse service.

D. When Applicant is indebted to Company for service furnished. Company may refuse to serve until indebtedness is paid.

E. When Customer or Applicant does not comply with state, municipal or other codes, rules and regulations applying to such service.

F. When directed to do so by governmental authority.

G. Service will not be supplied to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same or any other premises until payment of such indebtedness shall have been made. Service will not be continued to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same premises in accordance with 807 KAR 5:006, Section 14(1)(f). Unpaid balances of previously rendered Final Bills may be transferred to any account for which Customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred Final Bills will be subject to Company’s collections and disconnect procedures in accordance with 807 KAR 5:006, Section 14(1)(f). Final Bills transferred following a lapse in service will not be subject to disconnection unless: (1) such service was provided pursuant to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement which allows for such a disconnection; or (3) the current account is subsequently disconnected for service supplied at that point of delivery, at which time, all unpaid and past due balances must be paid prior to reconnect. Company shall have the right to transfer Final Bills between residential and commercial with residential characteristics (e.g., service supplying common use facilities of any apartment building) revenue classifications.

TERMS AND CONDITIONS

Discontinuance of Service

Service will not be supplied or continued to any premises if at the time of application for service Applicant is merely acting as an agent of a person or former customer who is indebted to Company for service previously supplied at the same or other premises until payment of such indebtedness shall have been made. Service will not be supplied where Applicant is a partnership or corporation whose general partner or controlling stockholder is a present or former customer who is indebted to Company for service previously supplied at the same premises until payment of such indebtedness shall have been made.

H. For non-payment of bills. Company shall have the right to discontinue service for non-payment of bills after Customer has been given at least ten days written notice separate from his original bill. Cut-off may be effected not less than twenty-seven (27) days after the mailing date of original bills unless, prior to discontinuance, a residential customer presents to Company a written certificate, signed by a physician, registered nurse, or public health officer, that such discontinuance will aggravate an existing illness or infirmity on the affected premises, in which case discontinuance may be effected not less than thirty (30) days from the original date of discontinuance. Company shall notify Customer, in writing, of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance.

I. For fraudulent or illegal use of service. When Company discovers evidence that by fraudulent or illegal means Customer has obtained unauthorized service or has diverted the service for unauthorized use or has obtained service without same being properly measured, the service to Customer may be discontinued without notice. Within twenty-four (24) hours after such termination, Company shall send written notification to Customer of the reasons for such discontinuance of service and of Customer's right to challenge the termination by filing a formal complaint with the Public Service Commission of Kentucky. Company's right of termination is separate from and in addition to any other legal remedies which the utility may pursue for illegal use or theft of service. Company shall not be required to restore service until Customer has complied with all rules of Company and regulations of the Commission and Company has been reimbursed for the estimated amount of the service rendered and the cost to Company incurred by reason of the fraudulent use.

When service has been discontinued for any of the above reasons, Company shall not be responsible for any damage that may result therefrom.

Discontinuance or refusal of service shall be in addition to, and not in lieu of, any other rights or remedies available to Company.

Company may defer written notice based on Customer's payment history provided Company continues to provide the required ten (10) days written notice prior to discontinuance of service.

Date of Issue: June 29, 2012
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

TERMS AND CONDITIONS

Line Extension Plan

A. AVAILABILITY

In all territory served by where Company does not have existing facilities to meet Customer's electric service needs.

B. DEFINITIONS

1) "Company" shall mean Kentucky Utilities Company.
2) "Customer" shall mean the applicant for service. When more than one electric service is requested by an applicant on the same extension, such request shall be considered one customer under this plan when the additional service request(s) is only for incidental or minor convenience loads or when the applicant for service is the developer of a subdivision.
3) "Line Extension" shall mean the single phase facilities required to serve Customer by the shortest route most convenient to Company from the nearest existing adequate Company facilities to Customer's delivery point, approved by Company, and excluding transformers, service drop, and meters, if required and normally provided to like customers.
4) "Permanent Service" shall mean service contracted for under the terms of the applicable rate schedule but not less than one year and where the intended use is not seasonal, intermittent, or speculative in nature.
5) "Commission" shall mean the Public Service Commission of Kentucky.

C. GENERAL

1) All extensions of service will be made through the use of overhead facilities except as provided in these rules.
2) Customer requesting service which requires an extension(s) shall furnish to Company, at no cost, properly executed easement(s) for right-of-way across Customer's property to be served.
3) Customer requesting extension of service into a subdivision, subject to the jurisdiction of a public commission, board, committee, or other agency with authority to zone or otherwise regulate land use in the area and require a plat (or Plan) of the subdivision, Customer shall furnish, at no cost, Company with the plat (or plan) showing street and lot locations with utility easement and required restrictions. Plats (or plans) supplied shall have received final approval of the regulating body and recorded in the office of the appropriate County Court Clerk when required. Should no regulating body exist for the area into which service is to be extended, Customer shall furnish Company the required easement.
4) The title to all extensions, rights-of way, permits, and easements shall be and remain with Company.
5) Where Company is required or elects to construct an additional extension or lateral to serve Customer or another customer, Company reserves the right to connect to any extension constructed under this plan and Customer shall grant to Company, at no cost, properly executed easement(s) for right-of-way across Customer's property for the additional extension or lateral.
6) Customer must agree in writing to take service when the extension is completed and have his building or other permanent facility wired and ready for connection.
7) Nothing herein shall be construed as preventing Company from making electric line extensions under more favorable terms than herein prescribed provided the potential revenue is of such amount and permanency as to warrant such terms and render economically

TERMS AND CONDITIONS

Line Extension Plan

C. GENERAL (continued)

feasible the capital expenditure involved and provided such extensions are made to other customers under similar conditions.

8) Company may require a non-refundable deposit in cases where Customer does not have a real need or in cases where the estimated revenue does not justify the investment.
9) Company shall not be obligated to extend its lines in cases where such extensions, in the good judgment of Company, would be infeasible, impractical, or contrary to good engineering or operating practice, unless otherwise ordered by Commission. T

D. NORMAL LINE EXTENSIONS

1) In accordance with 807 KAR 5:041, Section 11(1), Company will provide, at no cost, a line extension of up to 1,000 feet to Customer requesting permanent service where the installed transformer capacity does not exceed 25 kVA.
2) Where Customer requires poly-phase service or transformer capacity in excess of 25 kVA and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ 1 above.

E. OTHER LINE EXTENSIONS

1) In accordance with 807 KAR 5:041, Section 11(2), Company shall provide to Customer requesting permanent service a line extension in excess of 1,000 feet per customer but Company may require the total cost of the footage in excess of 1,000 feet per customer, based on the average cost per foot of the total extension, be deposited with Company by Customer.
2) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension for each additional customer connected during that year directly to the original extension for which the deposit was made.
3) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension less the length of the lateral or extension for each additional customer connected during that year by a lateral or extension to the original extension for which the deposit was made.
4) No refund shall be made for additional customers connected to an extension or lateral from the original extension for which the deposit was made.
5) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten (10) year refund period ends.
6) Where Customer requires poly-phase service or transformer capacity above 25 kVA per customer and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in OTHER LINE EXTENSIONS ¶ 1 above.

F. OVERHEAD LINE EXTENSIONS TO SUBDIVISIONS

1) In accordance with 807 KAR 5:041, Section 11(3), Customer desiring service extended for and through a subdivision may be required by Company to deposit the total cost of the extension.
2) Each year for ten (10) years Company shall refund to Customer, the cost of 1,000 feet of extension for each additional customer connected during that year directly to the original extension for which the deposit was made.
3) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten-year refund period ends.

TERMS AND CONDITIONS

Line Extension Plan

G. MOBILE HOME LINE EXTENSIONS

1) Company will make line extensions for service to mobile homes in accordance with 807 KAR 5:041, Section 12, and Commission's Order, dated August 9, 1991, in Case No. 91-213,
2) Company shall provide, at no cost, a line extension of up to 300 feet to Customer requesting permanent service for a mobile home.
3) Company shall provide to Customer requesting permanent service for a mobile home a line extension in excess of 300 feet and up to 1,000 feet but Company may require the total cost of the footage in excess of 300 feet, based on the average cost per foot of the total extension, be deposited with Company by Customer. Beyond 1,000 feet, the policies set forth in OTHER LINE EXTENSIONS shall apply.
4) Each year for four (4) years Company shall refund to Customer equal amounts of the deposit for the extension from 300 feet to 1,000 feet.
5) If service is disconnected for sixty (60) days, if the original mobile home is removed and not replaced by another mobile home or a permanent structure in sixty (60) days, the remainder of the deposit is forfeited.
6) No refund will be made except to the original customer.

H. UNDERGROUND LINE EXTENSIONS

General

1) Company will make underground line extensions for service to new residential customers and subdivisions in accordance with 807 KAR 5:041, Section 21.
2) In order that Company may make timely provision for materials, and supplies, Company may require Customer to execute a contract for an underground extension under these Terms and Conditions with Company at least six (6) months prior to the anticipated date service is needed and Company may require Customer to deposit with Company at least 10% of any amounts due under the contract at the time of execution. Customer shall deposit the balance of any amounts due under the contract with Company prior to ordering materials or commencement of actual construction by Company of facilities covered by the contract.
3) Customer shall give Company at least 120 days written notice prior to the anticipated date service is needed and Company will undertake to complete installation of its facilities at least thirty (30) days prior to that date. However, nothing herein shall be interpreted to require Company to extend service to portions of subdivisions not under active development.
4) At Company's discretion, Customer may perform a work contribution to Company's specifications, including but not limited to conduit, setting pads, or any required trenching and backfilling, and Company shall credit amounts due from Customer for underground service by Company's estimated cost for such work contribution.
5) Customer will provide, own, operate and maintain all electric facilities on his side of the point of delivery with the exception of Company's meter.
6) In consideration of Customer's underground service, Company shall credit any amounts due under the contract for each service at the rate of $50.00 or Company's average estimated installed cost for an overhead service whichever is greater.
7) Unit charges, where specified herein, are determined from Company's estimate of Company's average unit cost of such construction and the estimated cost differential between underground and overhead distribution systems in representative residential subdivisions.

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS
General (continued)

8) Three phase primary required to supply either individual loads or the local distribution system may be overhead unless Customer chooses underground construction and deposits with Company a non-refundable deposit for the cost differential.

Individual Premises

Where Customer requests and Company agrees to supply underground service to an individual premise, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.

Medium Density Subdivisions

1) A medium density residential subdivision is defined as containing ten or more lots for the construction of new residential buildings each designed for less than five (5)-family occupancy.

2) Customer shall provide any required trenching and backfilling or at Company's discretion be required to deposit with Company a non-refundable amount determined by a unit charge of $8.93 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.

3) The Customer may be required to advance to the Company the Company's full estimated cost of construction of an underground electric distribution extension. Where Customer is required to provide trenching and backfilling, advance will be the Company's full estimate cost of construction. Where Customer is required to deposit with the Company a non-refundable advance in place of trenching and backfilling, advance will be determined by a unit charge of $20.61 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.

4) Each year for ten (10) years Company shall refund to Customer an amount determined as follows:
   a. Where customer is required to provide trenching and backfilling, a refund of $5,000 for each customer connected during that year.
   b. Where customer is required to provide a non-refundable advance, 500 times the difference in the unit charge advance amount in 3) and the non-refundable unit charge advance in 2) for each customer connected during that year

5) In no case shall the refunds provided for herein exceed the amounts deposited less any non-refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends.

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS (continued)

High Density Subdivisions

1) A high density residential subdivision is defined as building complexes consisting of two or more buildings each not more than three stories above grade and each designed for five (5) or more family occupancy.
2) Customer shall provide any required trenching and backfilling or at Company's discretion be required to deposit with Company a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.
3) The Customer may be required to advance to the Company the Company's full estimated cost of construction of an underground electric distribution extension.
   i. Company shall refund to Customer any amounts due when permanent service is provided by Company to twenty (20%) percent of the family units in Customer's project.
   ii. In no case shall the refunds provided for herein exceed the amounts deposited less any non-refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends. T

Other Underground Subdivisions

In cases where a particular residential subdivision does not meet the conditions provided for above, Customer requests and Company agrees to supply underground service, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.

I. SPECIAL CASES

1) Where Customer requests service that is seasonal, intermittent, speculative in nature, at voltages of 34.5kV or greater, or where the facilities requested by Customer do not meet the Terms and Conditions outlined in previous sections of LINE EXTENSION PLAN and the anticipated revenues do not justify Company's installing facilities required to meet Customer's needs, Company may request that Customer deposit with Company a refundable amount to justify Company's investment. T
2) Each year for ten (10) years Company shall refund to Customer, an amount calculated by:
   a. Adding the sum of Customer's annual base rate monthly electric demand billing for that year to the sum of the annual base rate monthly electric billing of the monthly electric demand billing for that year of any customer(s), who connects directly to the facilities provided for in this agreement and requiring no further investment by Company
   b. times the refundable amount divided by the estimated total ten-year base rate electric demand billing required to justify the investment.
3) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten-year refund period ends.

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PURPOSE

To provide procedures for reducing the consumption of electric energy on the Kentucky Utilities Company (Company) system in the event of a capacity shortage and to restore service following an outage. Notwithstanding any provisions of these Energy Curtailment and Service Restoration Procedures, the Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that the Company believes necessary, in whatever order consistent with good utility practices and not on an unduly discriminatory basis, to preserve system integrity and to prevent the collapse of the Company's electric system or interconnected electric network or to restore service following an outage. Such actions will be taken giving priority to maintaining service to the Company's retail and full requirements customers relative to other sales whenever feasible and as allowed by law.

ENERGY CURTAILMENT PROCEDURE

PRIORITY LEVELS

For the purpose of these procedures, the following Priority Levels have been established:

I. Essential Health and Safety Uses -- to be given special consideration in these procedures shall, insofar as the situation permits, include the following types of use

A. "Hospitals", which shall be limited to institutions providing medical care to patients.

B. "Life Support Equipment", which shall be limited to kidney machines, respirators, and similar equipment used to sustain the life of a person.

C. "Police Stations and Government Detention Institutions", which shall be limited to essential uses required for police activities and the operation of facilities used for the detention of persons.

D. "Fire Stations", which shall be limited to facilities housing mobile fire-fighting apparatus.

E. "Communication Services", which shall be limited to essential uses required for telephone, telegraph, television, radio and newspaper operations, and operation of state and local emergency services.

F. "Water and Sewage Services", which shall be limited to essential uses required for the supply of water to a community, flood pumping and sewage disposal.

G. "Transportation and Defense-related Services", which shall be limited to essential uses required for the operation, guidance control and navigation of air, rail and mass transit systems, including those uses essential to the national defense and operation of state and local emergency services. These uses shall include essential street, highway and signal-lighting services.

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

Although, when practical, these types of uses will be given special consideration when implementing the manual load-shedding provisions of this program, any customer may be affected by rotating or unplanned outages and should install emergency generation equipment if continuity of service is essential. Where the emergency is system-wide in nature, consideration will be given to the use of rotating outages as operationally practicable. In case of customers supplied from two utility sources, only one source will be given special consideration. Also, any other customers who, in their opinion, have critical equipment should install emergency generation equipment.

Company maintains lists of customers with life support equipment and other critical needs for the purpose of curtailments and service restorations. Company, lacking knowledge of changes that may occur at any time in customer's equipment, operation, and backup resources, does not assume the responsibility of identifying customers with priority needs. It shall, therefore, be the customer's responsibility to notify Company if Customer has critical needs.

II. Critical Commercial and Industrial Uses -- Except as described in Section III below, these uses shall include commercial or industrial operations requiring regimented shutdowns to prevent conditions hazardous to the general population, and to energy utilities and their support facilities critical to the production, transportation, and distribution of service to the general population. Company shall maintain a list of such customers for the purpose of curtailments and service restoration.

III. Residential Use -- The priority of residential use during certain weather conditions (for example severe winter weather) will receive precedence over critical commercial and industrial uses. The availability of Company service personnel and the circumstances associated with the outage will also be considered in the restoration of service.

IV. Non-critical commercial and industrial uses.

V. Nonessential Uses -- The following and similar types of uses of electric energy shall be considered nonessential for all customers:

A. Outdoor flood and advertising lighting, except for the minimum level to protect life and property, and a single illuminated sign identifying commercial facilities when operating after dark.

B. General interior lighting levels greater than minimum functional levels.

C. Show-window and display lighting.

D. Parking-lot lighting above minimum functional levels.

E. Energy use to lower the temperature below 78 degrees during operation of cooling equipment and above 65 degrees during operation of heating equipment.

F. Elevator and escalator use in excess of the minimum necessary for non-peak hours of use.

Date of Issue: June 29, 2012
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

G. Energy use greater than that which is the minimum required for lighting, heating, or cooling of commercial or industrial facilities for maintenance cleaning or business-related activities during non-business hours.

Non-jurisdictional customers will be treated in a manner consistent with the curtailment procedures contained in the service agreement between the parties or the applicable tariff.

CURTAILMENT PROCEDURES

In the event Company's load exceeds internal generation, transmission, or distribution capacity, or other system disturbances exist, and internal efforts have failed to alleviate the problem, including emergency energy purchases, the following steps may be taken, individually or in combination, in the order necessary as time permits:

1. Customers having their own internal generation capacity will be curtailed, and customers on curtailable contracts will be curtailed for the maximum hours and load allowable under their contract. Nothing in this procedure shall limit Company's rights under the Curtailable Service Rider tariff.
2. Power output will be maximized at Company's generating units.
3. Company use of energy at its generating stations will be reduced to a minimum.
4. Company's use of electric energy in the operation of its offices and other facilities will be reduced to a minimum.
5. The Kentucky Public Service Commission will be advised of the situation.
6. An appeal will be made to customers through the news media and/or personal contact to voluntarily curtail as much load as possible. The appeal will emphasize the defined priority levels as set forth above.
7. Customers will be advised through the use of the news media and personal contact that load interruption is imminent.
8. Implement procedures for interruption of selected distribution circuits.

SERVICE RESTORATION PROCEDURES

Where practical, priority uses will be considered in restoring service and service will be restored in the order I through IV as defined under PRIORITY LEVELS. However, because of the varieties of unpredictable circumstances which may exist or precipitate outages, it may be necessary to balance specific individual needs with infrastructure needs that affect a larger population. When practical, Company will attempt to provide estimates of repair times to aid customers in assessing the need for alternative power sources and temporary relocations.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(1)(a)8
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

The utility's proposed tariff changes, identified in compliance with 807 KAR 5:011, shown either by:

(a) Providing the present and proposed tariffs in comparative form on the same sheet side by side or on facing sheets side by side; or,

(b) Providing a copy of the present tariff indicating proposed additions by italicized inserts or underscoring and striking over proposed deletions.

Response:

Please see the attached present and proposed tariffs in comparative form on the same sheet side-by-side. Please note the following:

- On each sheet of the side-by-side comparison the present tariff is on the left and the proposed tariff is on the right.

P.S.C. No. 15
Canceling P.S.C. No. 14

Kentucky Utilities Company

One Quality Street
Lexington, Kentucky

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

In seventy-seven counties in the State of Kentucky
as depicted on territorial maps as filed with the

PUBLIC SERVICE COMMISSION

OF KENTUCKY

Date of Issue
August 6, 2010

Date Effective
August 1, 2010

Issued by
Lonnie E. Bellar, Vice President
State Regulation and Rates

P.S.C. No. 16
Canceling P.S.C. No. 15

Kentucky Utilities Company

One Quality Street
Lexington, Kentucky

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

In seventy-seven counties in the Commonwealth of Kentucky
as depicted on territorial maps as filed with the

PUBLIC SERVICE COMMISSION

OF KENTUCKY

Date of Issue
June 29, 2012

Date Effective
August 1, 2012
Subject to Article I.1.1 of the
Settlement Agreement attached to
and Approved in September 30, 2010
KPSC Order in Case No. 2010-00204

Issued by
Lonnie E. Bellar, Vice President
State Regulation and Rates

Kentucky Utilities Company

P.S.C. No. 15, Fifth Revision of Original Sheet No. 1
Canceling P.S.C. No. 15, Fourth Revision of Original Sheet No. 1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

Title		Sheet Number	Effective Date
General Index		1	04-09-12
SECTION 1 - Standard Rate Schedules			
RS	Residential Service	5	02-29-12
VFD	Volunteer Fire Department Service	7	02-29-12
GS	General Service	10	02-29-12
AES	All Electric School	12	02-29-12
PS	Power Service	15	02-29-12
TODS	Time-of-Day Secondary Service	20	02-29-12
TODP	Time-of-Day Primary Service	22	02-29-12
RTS	Retail Transmission Service	25	02-29-12
FLS	Fluctuating Load Service	30	02-29-12
ST. LT.	Street Lighting Service	35	02-29-12
P.O. LT.	Private Outdoor Lighting	36	02-29-12
LE	Lighting Energy Service	37	02-29-12
TE	Traffic Energy Service	38	02-29-12
DSK	Dark Sky Friendly	39	02-29-12
CTAC	Cable Television Attachment Charges	40	08-01-10
	Special Charges	45	08-01-10
	Returned Payment Charge		
	Meter Test Charge		
	Disconnect/Reconnect Service Charge		
	Meter Pulse Charge		
	Meter Data Processing Charge		
SECTION 2 – Riders to Standard Rate Schedules			
CSR10	Curtailable Service Rider 10	50	08-01-10
CSR30	Curtailable Service Rider 30	51	08-01-10
LRI	Load Reduction Incentive Rider	53	08-01-06
SQF	Small Capacity Cogeneration Qualifying Facilities	55	06-30-10
LQF	Large Capacity Cogeneration Qualifying Facilities	56	04-17-99
NMS	Net Metering Service	57	08-17-09
EF	Excess Facilities	60	08-01-10
RC	Redundant Capacity	61	08-01-10
SS	Supplemental/Stand-By Service	62	08-01-10
IL	Intermittent Load Rider	65	08-01-10
TS	Temporary/Seasonal Service Rider	66	08-01-10
KWH	Kilowatt-Hours Consumed By Lighting Unit	67	03-01-00
GER	Green Energy Riders	70	06-01-10
EDR	Economic Development Rider	71	08-11-11
RTP	Real Time Pricing Rider	78	04-09-12

Date of Issue: April 9, 2012
Date Effective: April 9, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00010 dated March 20, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

Title		Sheet Number	Effective Date	
General Index		1	08-01-12	T
SECTION 1 - Standard Rate Schedules				
RS	Residential Service	5	08-01-12	T
VFD	Volunteer Fire Department Service	7	08-01-12	
GS	General Service	10	08-01-12	
AES	All Electric School	12	08-01-12	
PS	Power Service	15	08-01-12	
TODS	Time-of-Day Secondary Service	20	08-01-12	
TODP	Time-of-Day Primary Service	22	08-01-12	
RTS	Retail Transmission Service	25	08-01-12	
FLS	Fluctuating Load Service	30	08-01-12	
LS	Lighting Service	35	08-01-12	
RLS	Restricted Lighting Service	36	08-01-12	
LE	Lighting Energy Service	37	08-01-12	
TE	Traffic Energy Service	38	08-01-12	
CTAC	Cable Television Attachment Charges	40	08-01-12	
	Special Charges	45	08-01-12	
	Returned Payment Charge			
	Meter Test Charge			
	Disconnect/Reconnect Service Charge			
	Meter Pulse Charge			
	Meter Data Processing Charge			
SECTION 2 – Riders to Standard Rate Schedules				
CSR10	Curtailable Service Rider 10	50	08-01-12	T
CSR30	Curtailable Service Rider 30	51	08-01-12	T
SQF	Small Capacity Cogeneration Qualifying Facilities	55	06-30-10	
LQF	Large Capacity Cogeneration Qualifying Facilities	56	04-17-99	
NMS	Net Metering Service	57	08-17-09	
EF	Excess Facilities	60	08-01-12	T
RC	Redundant Capacity	61	08-01-12	T
SS	Supplemental/Stand-By Service	62	08-01-12	T
IL	Intermittent Load Rider	65	08-01-12	T
TS	Temporary/Seasonal Service Rider	66	08-01-12	T
KWH	Kilowatt-Hours Consumed By Lighting Unit	67	03-01-00	
GER	Green Energy Riders	70	06-01-10	
EDR	Economic Development Rider	71	08-11-11	

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Thirteenth Revision of Original Sheet No. 1.1
Canceling P.S.C. No. 15, Twelfth Revision of Original Sheet No. 1.1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

Date of Issue: April 30, 2012
Date Effective: May 31, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 1.1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 5
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 5

Standard Rate RS
Residential Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for single phase delivery to single family residential service subject to the terms and conditions on Sheet No. 100 of this Tariff. Three phase service under this rate schedule is restricted to those customers being billed on this rate schedule as of July 1, 2004.

RATE

Basic Service Charge:	\$ 8.50 per month
Plus an Energy Charge of:	\$ 0.06987 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month's charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 5

Standard Rate RS
RESIDENTIAL SERVICE

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for single phase delivery to single family residential service subject to the terms and conditions on Sheet No. 100 of this Tariff. Three phase service under this rate schedule is restricted to those customers being billed on this rate schedule as of July 1, 2004.

RATE

Basic Service Charge:	\$13.00 per month	I
Plus an Energy Charge of:	\$ 0.07235 per kWh	I

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month's charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 7
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 7

Standard Rate VFD

Volunteer Fire Department Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for single-phase delivery, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load.

DEFINITION
To be eligible for this rate a volunteer fire department is defined as:

1) having at least 12 members and a chief,
2) having at least one fire fighting apparatus, and
3) half the members must be volunteers

RATE

Basic Service Charge:	$ 8.50 per month
Plus an Energy Charge of:	$ 0.06987 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 7

Standard Rate VFD

VOLUNTEER FIRE DEPARTMENT SERVICE

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for single-phase delivery, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load.

DEFINITION
To be eligible for this rate a volunteer fire department is defined as:

1) having at least 12 members and a chief,
2) having at least one firefighting apparatus, and
3) half the members must be volunteers

RATE

Basic Service Charge:	$13.00 per month
Plus an Energy Charge of:	$ 0.07235 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 10
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 10

Standard Rate GS
General Service Rate

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
To general lighting and small power loads for secondary service.

Service under this schedule will be limited to average maximum loads not exceeding 50 kW. Existing customers with an average maximum load exceeding 50 kW who are receiving service under P.S.C. 13, Fourth Revision of Original Sheet No. 10 as of February 6, 2009, will continue to be served under this rate at their option. New customers, upon demonstrating an average demand of 50 kW or greater, will be served under the appropriate rate schedule.

RATE

Basic Service Charge:	\$17.50 per month for single-phase service \$32.50 per month for three-phase service
Plus an Energy Charge of:	\$ 0.08332 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 10

Standard Rate GS
GENERAL SERVICE RATE

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
To general lighting and small power loads for secondary service.

Service under this schedule will be limited to customers whose 12-month-average monthly maximum loads do not exceed 50 kW. Existing customers with 12-month-average maximum monthly loads exceeding 50 kW who are receiving service under P.S.C. 13, Fourth Revision of Original Sheet No. 10 as of February 6, 2009, will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer. T

RATE

Basic Service Charge:	\$20.00 per month for single-phase service \$35.00 per month for three-phase service	I I
Plus an Energy Charge of:	\$ 0.08678 per kWh	I

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD T
If Company determines based on Customer's usage history that Customer may be exceeding the maximum load permitted under Rate GS, Company may, at its discretion, equip Customer with a meter capable of measuring demand to determine Customer's continuing eligibility for Rate GS. If Customer is equipped with a demand-measuring meter, Customer's load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

The proposed KU General Service Rate GS is contained on two pages instead of the current one page.

GS
GENERAL SERVICE RATE T

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 12
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 12

Standard Rate — AES — All Electric School

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate is available where energy requirement for (l) a complex of school buildings on a central campus, (2) an individual school building, or (3) an addition to an existing school building is served electrically by Kentucky Utilities Company; such energy requirement to include, but not be limited to, lighting, heating, cooling and water heating. Other school buildings not so receiving every energy requirement electrically shall be separately metered from the above defined service and served under another appropriate applicable rate. At those locations where the school owns its distribution system and makes the service connections therefrom to the various buildings and/or load centers, the Company shall be given the option of providing service by use of the existing Customer owned distribution system, or of constructing its own facilities in accordance with the Company's Overhead Construction Standards. In any event, the Company's investment in construction may be limited to an amount not exceeding twice the estimated annual revenue from the service so connected. If the Customer desires, he will be allowed to make a contribution for the remaining requirement, so as to receive service under this schedule.

School buildings, as referred to herein, shall be defined as buildings used as classrooms, laboratories, gymnasiums, libraries, cafeterias, school related offices or for other bona fide school purposes by duly constituted school authorities of Kentucky. This Rate Schedule is not available to include buildings of privately operated kindergartens or day care centers and is restricted to those customers receiving service on this rate as of February 6, 2009.

Other fuels may be used as incidental to and for instructional laboratory and other miscellaneous purposes without affecting the availability of this rate.

RATE

Basic Service Charge:	$17.50 per meter per month for single-phase service $32.50 per meter per month for three-phase service
Plus an Energy Charge of:	$ 0.06670 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 12

Standard Rate — AES — ALL ELECTRIC SCHOOL

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate is available for secondary and primary service to: T
(1) a complex of school buildings on a central campus,
(2) an individual school building, or
(3) an addition to an existing school building.

School buildings, as referred to herein, shall be defined as buildings used as classrooms, laboratories, gymnasiums, libraries, cafeterias, school related offices or for other bona fide school purposes by duly constituted school authorities of Kentucky. Served electrically by Kentucky Utilities Company, such energy requirements include, but are not limited to, lighting, heating, cooling, and water heating. School buildings not receiving every energy requirement electrically shall be separately metered from the above defined service and served under the applicable rate. Other fuels may be used as incidental to and for instructional laboratory and other miscellaneous purposes without affecting the availability of this rate.

At those locations where the school owns its distribution system and makes the service connections to the various buildings and/or load centers, Company shall be given the option of T
providing service by use of the existing Customer-owned distribution system, or of constructing T
its own facilities in accordance with the Company's Overhead Construction Standards. In any event, Company's investment in the facilities it provides may be limited to an amount not T
exceeding twice the estimated annual revenue from Customer's service. Should Company's investment in the facilities required to provide service to Customer exceed twice the revenue anticipated from the service to Customer and at Customer's option, Customer may make a contribution for the difference in the investment required in facilities necessary to provide service and twice the anticipated revenue, so as to receive service under this schedule.

This Rate Schedule is not available to privately operated kindergartens or daycare centers and is restricted to those customers who were qualified for and being served on Rate AES as of July 1, 2011. Because this rate schedule is closed to new customers, if Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule.

RATE

Basic Service Charge:	$20.00 per meter per month for single-phase service $35.00 per meter per month for three-phase service	I I
Plus an Energy Charge of:	$ 0.07060 per kWh	I

T

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 12.1

Standard Rate A.E.S.

All Electric School

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month's charges.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 12.1

Standard Rate A.E.S.

ALL ELECTRIC SCHOOL

ADJUSTMENT CLAUSES T
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month's charges.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 15
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 15

Standard Rate PS
Power Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rate schedule is available for secondary or primary service.

Service under this schedule will be limited to minimum average secondary loads of 50 kW and maximum average loads not exceeding 250 kW. Secondary or primary customers receiving service under PSC 13, Fourth Revision of Original Sheet No. 20, Large Power Service, or Fourth Revision of Original Sheet No. 30, Mine Power Service, as of February 6, 2009, with loads not meeting these criteria will continue to be served under this rate at their option. Customers initiating service on this rate after February 6, 2009, and whose load characteristics subsequently do not meet these criteria will be billed on the appropriate rate.

RATE

	Secondary	Primary
Basic Service Charge per month:	$90.00	$90.00
Plus an Energy Charge per kWh of:	$ 0.03300	$ 0.03300
Plus a Demand Charge per kW of:		
Summer Rate: (Five Billing Periods of May through September)	$13.90	$13.72
Winter Rate: (All other months)	$11.65	$11.45

Where the monthly billing demand is the greater of:
a) the maximum measured load in the current billing period but not less than 50 kW for secondary service or 25 kW for primary service, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 60% of the contract capacity based on the maximum expected load on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 15

Standard Rate PS
POWER SERVICE

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rate schedule is available for secondary or primary service.

Service under this schedule will be limited to customers whose 12-month-average monthly T
minimum secondary loads exceed 50 kW and whose 12-month-average monthly maximum loads T
do not exceed 250 kW. Secondary or primary customers receiving service under PSC 13, T
Fourth Revision of Original Sheet No. 20, Large Power Service, or Fourth Revision of Original Sheet No. 30, Mine Power Service, as of February 6, 2009, with loads not meeting these
criteria will continue to be served under this rate at their option. If Customer is taking service T
under this rate schedule and subsequently elects to take service under another rate schedule, T
Customer may not again take service under this rate schedule unless and until Customer T
meets the Availability requirements that would apply to a new customer. T

RATE

	Secondary	Primary	
Basic Service Charge per month:	$90.00	$125.00	I
Plus an Energy Charge per kWh of:	$ 0.03349	$ 0.03349	I
Plus a Demand Charge per kW of:			
Summer Rate: (Five Billing Periods of May through September)	$14.40	$ 14.75	I
Winter Rate: (All other months)	$12.10	$ 12.73	I

Where the monthly billing demand is the greater of:
a) the maximum measured load in the current billing period but not less than 50 kW for secondary service or 25 kW for primary service, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 60% of the contract capacity based on the maximum expected load on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

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School Tax	Sheet No. 91

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 15.1

Standard Rate — PS — Power Service

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed based on the measured kVA times 90 percent of the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD).

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured X 90\%}}{\text{Power Factor (in percent)}}$$

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Contracts under this rate shall be for an initial term of one (1) year, remaining in effect from month to month thereafter until terminated by notice of either party to the other.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 15.1

Standard Rate — PS — POWER SERVICE

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed based on the measured kVA times 90 percent of the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD).

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured X 90\%}}{\text{Power Factor (in percent)}}$$

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Contracts under this rate shall be for an initial term of one (1) year, remaining in effect from month to month thereafter until terminated by notice of either party to the other.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

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Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 20
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 20

Standard Rate — TODS
Time-of-Day Secondary Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for secondary service. Service under this schedule will be limited to minimum average loads of 250kW and maximum average loads not exceeding 5,000 kW. Customers initiating service on this rate whose load characteristics subsequently do not meet these criteria will be billed on the appropriate rate.

RATE

Basic Service Charge per month:	$200.00
Plus an Energy Charge per kWh of:	$ 0.03490
Plus a Maximum Load Charge per kW of:	
Peak Demand Period	$ 3.89
Intermediate Demand Period	$ 2.43
Base Demand Period	$ 3.05

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kW, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD
The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 20

Standard Rate — TODS
TIME-OF-DAY SECONDARY SERVICE

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for secondary service. Service under this schedule will be limited to T
customers whose 12-month-average monthly minimum average loads exceed 250 kW and T
whose 12-month-average monthly maximum average loads do not exceed 5,000 kW. T

RATE

Basic Service Charge per month:	$200.00	
Plus an Energy Charge per kWh of:	$ 0.03590	I
Plus a Maximum Load Charge per kW of:		
Peak Demand Period	$ 4.50	I
Intermediate Demand Period	$ 2.80	I
Base Demand Period	$ 3.50	I

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kW, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD
The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Standard Rate — TODS
Time-of-Day Secondary Service

DETERMINATION OF MAXIMUM LOAD (continued)

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed based on the measured kVA times 90 percent, at the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD)

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured x 90\%}}{\text{Power Factor (in percent)}}$$

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Standard Rate — TODS
TIME-OF-DAY SECONDARY SERVICE

DETERMINATION OF MAXIMUM LOAD (continued)

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed based on the measured kVA times 90 percent, at the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD)

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured x 90\%}}{\text{Power Factor (in percent)}}$$

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

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Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 22
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 22

Standard Rate — TODP
Time-of-Day Primary Service

APPLICABLE
In all territory served

AVAILABILITY OF SERVICE
This schedule is available for primary service. Service under this schedule will be limited to minimum average loads of 250 kVA and maximum new loads not exceeding 50,000 kVA. Existing customers may increase loads to a maximum of 75,000 kVA by up to 2,000 kVA per year or in greater increments with approval of Company's transmission operator. Customers initiating service on this rate whose load characteristics subsequently do not meet these criteria will be billed on the appropriate rate or have a rate developed based on their electrical characteristics.

RATE

Basic Service Charge per month:	$300.00
Plus an Energy Charge per kWh of:	$ 0.03522
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 3.67
Intermediate Demand Period	$ 2.31
Base Demand Period	$ 1.28

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 22

Standard Rate — TODP
TIME-OF-DAY PRIMARY SERVICE

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for primary service. Service under this schedule will be limited to customers whose 12-month-average monthly minimum average loads exceed 250 kVA and whose 12-month-average monthly maximum new loads do not exceed 50,000 kVA. Existing customers may increase loads to a 12-month-average monthly maximum of 75,000 kVA by up to 2,000 kVA per year or in greater increments with approval of Company's transmission operator. T

RATE

Basic Service Charge per month:	$300.00	
Plus an Energy Charge per kWh of:	$ 0.03557	I
Plus a Maximum Load Charge per kVA of:		
Peak Demand Period	$ 4.30	I
Intermediate Demand Period	$ 2.70	I
Base Demand Period	$ 1.60	I

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
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Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Date of Issue: June 29, 2012
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Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 22.1

Standard Rate — TODP

Time-of-Day Primary Service

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party ninety (90) days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 22.1

Standard Rate — TODP

TIME-OF-DAY PRIMARY SERVICE

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party ninety (90) days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

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Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 25
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 25

Standard Rate — RTS
Retail Transmission Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for transmission service. Service under this schedule will be limited to maximum new loads not exceeding 50,000 kVA. Existing customers may increase loads to a maximum of 75,000 kVA by up to 2,000 kVA per year or in greater increments with approval of Company's transmission operator. Customers initiating service on this rate whose load characteristics subsequently do not meet these criteria will be billed on the appropriate rate or have a rate developed based on their electrical characteristics.

RATE

Basic Service Charge per month:	$500.00
Plus an Energy Charge per kWh of:	$ 0.03414
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 3.54
Intermediate Demand Period	$ 2.30
Base Demand Period	$ 0.85

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 25

Standard Rate — RTS
RETAIL TRANSMISSION SERVICE

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for transmission service. Service under this schedule will be limited to customers whose 12-month-average monthly maximum new loads do not exceed 50,000 kVA. Existing customers may increase loads to a 12-month-average monthly maximum of 75,000 kVA by up to 2,000 kVA per year or in greater increments with approval of Company's transmission operator. T

RATE

Basic Service Charge per month:	$750.00	I
Plus an Energy Charge per kWh of:	$ 0.03408	R
Plus a Maximum Load Charge per kVA of:		
Peak Demand Period	$ 3.90	I
Intermediate Demand Period	$ 2.90	I
Base Demand Period	$ 1.30	I

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 25.1

Standard Rate — RTS

Retail Transmission Service

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year and for yearly periods thereafter until terminated by either party giving written notice to the other party ninety (90) days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 25.1

Standard Rate — RTS

RETAIL TRANSMISSION SERVICE

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year and for yearly periods thereafter until terminated by either party giving written notice to the other party ninety (90) days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: June 29, 2012
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 30
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 30

Standard Rate — FLS
Fluctuating Load Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for primary or transmission service to customers up to an aggregate of two hundred (200) MVA for all customers taking service under this schedule and under the Fluctuating Load Service Rate FLS schedule of Louisville Gas and Electric Company. This schedule is restricted to individual customers whose monthly demand is twenty (20) MVA or greater. A customer is defined as a fluctuating load if that customer's load either increases or decreases twenty (20) MVA or more per minute or seventy (70) MVA or more in ten (10) minutes when such increases or decreases exceed one (1) occurrence per hour during any hour of the billing month.

Subject to the above aggregate limit of two hundred (200) MVA, this schedule is mandatory for all customers whose load is defined as fluctuating and not served on another standard rate schedule as of July 1, 2004.

BASE RATE

	Primary	Transmission
Basic Service Charge per month:	$500.00	$500.00
Plus an Energy Charge per kWh of:	$ 0.03419	$ 0.02947
Plus a Maximum Load Charge per kVA of:		
Peak Demand Period	$ 2.30	$ 2.30
Intermediate Demand Period	$ 1.41	$ 1.41
Base Demand Period	$ 1.57	$ 0.82

Where:
1) the monthly billing demand for the Primary Peak and Intermediate Demand Periods is the greater of:
   a) the maximum measured load in the current billing period, or
   b) a minimum of 60% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

   the monthly billing demand for the Primary Base Demand Period is the greater of:
   a) the maximum measured load in the current billing period but not less than 20,000 kVA, or
   b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
   c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.
2) the monthly billing demand for the Transmission Peak and Intermediate Demand Periods is the greater of:
   a) the maximum measured load in the current billing period, or
   b) a minimum of 40% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 30

Standard Rate — FLS
Fluctuating Load Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for primary or transmission service to customers up to an aggregate of two hundred (200) MVA for all customers taking service under this schedule and under the Fluctuating Load Service Rate FLS schedule of Louisville Gas and Electric Company. This schedule is restricted to individual customers whose monthly demand is twenty (20) MVA or greater. A customer is defined as a fluctuating load if that customer's load either increases or decreases twenty (20) MVA or more per minute or seventy (70) MVA or more in ten (10) minutes when such increases or decreases exceed one (1) occurrence per hour during any hour of the billing month.

Subject to the above aggregate limit of two hundred (200) MVA, this schedule is mandatory for all customers whose load is defined as fluctuating and not served on another standard rate schedule as of July 1, 2004.

BASE RATE

	Primary	Transmission	
Basic Service Charge per month:	$750.00	$750.00	I
Plus an Energy Charge per kWh of:	$ 0.03419	$ 0.03092	I
Plus a Maximum Load Charge per kVA of:			
Peak Demand Period	$ 2.40	$ 2.40	I
Intermediate Demand Period	$ 1.44	$ 1.44	I
Base Demand Period	$ 1.75	$ 1.00	I

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of: T
   a) the maximum measured load in the current billing period, or T
   b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of: T
   a) the maximum measured load in the current billing period but not less than 20,000 kVA, or
   b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
   c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

T

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 30.1

Standard Rate FLS

Fluctuating Load Service

the monthly billing demand for the Transmission Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 20,000 kVA, or
b) a minimum of 40% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 40% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 5-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 30.1

Standard Rate FLS

Fluctuating Load Service

T

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 5-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE T

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% T
late payment charge will be assessed on the current month's charges. T

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

LATE PAYMENT CHARGE

If full payment is not received within three (3) calendar days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Unless terminated by mutual agreement, the initial term of contract for service shall be for a fixed term of five years with successive one year term renewal until canceled by either party giving at least one (1) year written notice to the other prior to the end of the initial term or the then current annual renewal period, as applicable.

PROTECTION OF SERVICE

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other undesirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:056, Section 14(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. Company shall be held harmless for any damages or economic loss resulting from such termination of service. If requested by Company, Customer shall provide all available information to Company that aids Company in enforcing its service standards. If Company at any time has a reasonable basis for believing that Customer's proposed or existing use of the service provided will not comply with the service standards for interference, fluctuations, or harmonics, Company may engage such experts and/or consultants as Company shall determine are appropriate to advise Company in ensuring that such interference, fluctuations, or harmonics are within acceptable standards. Should such experts and/or consultants determine Customer's use of service is unacceptable, Company's use of such experts and/or consultants will be at the Customer's expense.

SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA

Company reserves the right to interrupt up to 95% of Customer's load to facilitate Company compliance with system contingencies and with industry performance criteria. Customer will permit Company to install electronic equipment and associated real-time metering to permit Company interruption of Customer's load. Such equipment will immediately notify Customer five (5) minutes before an electronically initiated interruption that will begin immediately thereafter and last no longer than ten (10) minutes nor shall the interruptions exceed twenty (20) per month. Such interruptions will not be accumulated nor credited against annual hours, if any, under the CURTAILABLE SERVICE RIDERS CSR10 AND CSR 30. Company's right to

TERM OF CONTRACT T

Unless terminated by mutual agreement, the initial term of contract for service shall be for a fixed term of five years with successive one year term renewal until canceled by either party giving at least one (1) year written notice to the other prior to the end of the initial term or the then current annual renewal period, as applicable.

PROTECTION OF SERVICE

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other undesirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 14(1)(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. T Company shall be held harmless for any damages or economic loss resulting from such termination of service. If requested by Company, Customer shall provide all available information to Company that aids Company in enforcing its service standards. If Company at any time has a reasonable basis for believing that Customer's proposed or existing use of the service provided will not comply with the service standards for interference, fluctuations, or harmonics, Company may engage such experts and/or consultants as Company shall determine are appropriate to advise Company in ensuring that such interference, fluctuations, or harmonics are within acceptable standards. Should such experts and/or consultants determine Customer's use of service is unacceptable, Company's use of such experts and/or consultants will be at the Customer's expense.

SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA

Company reserves the right to interrupt up to 95% of Customer's load to facilitate Company compliance with system contingencies and with industry performance criteria. Customer will permit Company to install electronic equipment and associated real-time metering to permit Company interruption of Customer's load. Such equipment will immediately notify Customer five (5) minutes before an electronically initiated interruption that will begin immediately thereafter and last no longer than ten (10) minutes nor shall the interruptions exceed twenty (20) per month. Such interruptions will not be accumulated nor credited against annual hours, if any, under the CURTAILABLE SERVICE RIDERS CSR10 AND CSR 30. Company's right to

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 30.3
P.S.C. No. 15, Original Sheet No. 30.3

Standard Rate | FLS
Fluctuating Load Service

Interrupt under this provision is restricted to responses to unplanned outage or de-rates of LG&E and KU Energy LLC System (LKE System) owned or purchased generation or when Automatic Reserve Sharing is *invoked* with ECAR or an ISO/TRO. LKE System, as used herein, shall consist of KU and LG&E. At customer's request, Company shall provide documentation of the need for interruption under this provision within sixty (60) days of the end of the applicable billing period.

LIABILITY
In no event shall Company have any liability to the Customer or any other party affected by the electrical service to the Customer for any consequential, *indirect*, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to the Customer or any other party. In the event that the Customer's use of Company's service causes damage to Company's property or injuries to persons, the Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: November 2, 2010
Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2010-00204 dated September 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 30.3

Standard Rate | FLS
Fluctuating Load Service

Interrupt under this provision is restricted to responses to unplanned outage or de-rates of LG&E and KU Energy LLC System (LKE System) owned or purchased generation or when Automatic Reserve Sharing is invoked. LKE System, as used herein, shall consist of KU and LG&E. At customer's request, Company shall provide documentation of the need for interruption under this provision within sixty (60) days of the end of the applicable billing period. T

LIABILITY
In no event shall Company have any liability to the Customer or any other party affected by the electrical service to the Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to the Customer or any other party. In the event that the Customer's use of Company's service causes damage to Company's property or injuries to persons, the Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 35
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 35

Standard Rate — ST. LT.
Street Lighting Service

AVAILABILITY OF SERVICE

This rate schedule is available, for the various types of street lighting services shown herein, in any community in which the Company has an electric franchise. Service is subject to the provisions herein and the provisions of the Company's standard contract for street lighting service. Should the service not meet these standard provisions, then the Company reserves the right to revise the charges listed hereinafter so as to include any additional or unusual cost involved.

OVERHEAD SERVICE

1. **STANDARD OVERHEAD SYSTEM:** Street lighting equipment furnished under the Standard Overhead Rate shall consist of wood poles, brackets, appropriate fixtures for the lamps being used, 150 feet of street lighting circuit, protective equipment, controls and transformers. The Company will install, own, operate and maintain the entire street lighting system, including circuits, lighting fixtures and lamp replacements. The Customer shall pay the Standard Overhead Rate.

2. **ORNAMENTAL OVERHEAD SYSTEM:** The Company will, upon request, furnish under the Ornamental Overhead Rate, ornamental poles of the Company's choosing, together with overhead wiring and all other equipment and provisions mentioned in Section 1 above. The Customer will pay the Ornamental Overhead Rate.

3. **OTHER THAN CONVENTIONAL OVERHEAD SYSTEMS:** Should the Customer require, either initially or upon replacement, a system or equipment other than that described in Sections 1 and 2 above for lamp sizes as provided herein, (this constituting a conventional overhead system) the Customer may make a non-refundable contribution to the Company equal to the difference in the installed cost between the system or equipment so required and the cost of a conventional overhead system as hereinbefore defined. In a similar manner the Customer will pay the difference in the cost of operating and maintaining such a system or equipment and the cost of operating and maintaining a conventional Overhead System. Any installation costs which are to be borne by the Customer should be paid at the time of installation.

RATE

TYPE OF FIXTURE	LOAD/LIGHT	RATE PER LIGHT PER MONTH STANDARD	ORNAMENTAL
HIGH PRESSURE SODIUM			
4,000 Lumens (approximately)	0.060 kW/Light	$ 6.93	$ 9.76
5,800 " "	0.083 kW/Light	7.90	10.73
9,500 " "	0.117 kW/Light	8.41	11.45
22,000 " "	0.242 kW/Light	13.04	16.08
50,000 " "	0.471 kW/Light	20.95	22.51
***MERCURY VAPOR**			
7,000 Lumens (approximately)	0.207 kW/Light	$ 8.72	$10.94
10,000 " "	0.294 kW/Light	10.29	12.26
20,000 " "	0.453 kW/Light	12.57	14.14
***INCANDESCENT**			
1,000 Lumens (approximately)	0.102 kW/Light	$ 3.08	$ 3.73
2,500 " "	0.201 kW/Light	4.09	4.88
4,000 " "	0.327 kW/Light	6.08	7.00
6,000 " "	0.447 kW/Light	8.11	9.13

NOTE: * Incandescent and Mercury Vapor are restricted to those fixtures in service. Upon failure, existing fixtures will either be removed from service or replaced with available lighting at the customer's option.

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 35

Standard Rate — LS
Lighting Service N

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rate schedule is offered, under the conditions set out hereinafter, for lighting applications such as, but not limited to, the illumination of street, driveways, yards, lots, and other outdoor areas where secondary voltage of 120/240 is available.

Service will be provided under written contract, signed by customer prior to service commencing, when additional facilities are required.

Units marked with an asterisk (*) are not available for use in residential neighborhoods except by municipal authorities.

OVERHEAD SERVICE

Based on Customer's lighting choice, Company will furnish, own, install, and maintain the lighting unit. A basic overhead service includes lamp, fixture, photoelectric control, mast arm, and, if needed, up to 150 feet of conductor per fixture on existing wood poles (fixture only). Company will, upon request, furnish ornamental poles of Company's choosing, together with overhead wiring and all other equipment mentioned for basic overhead service.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Ornamental
High Pressure Sodium					
462/472	Cobra Head	5,800	0.083	$ 8.33	$11.32
463/473	Cobra Head	9,500	0.117	8.87	12.08
464/474	Cobra Head	22,000*	0.242	13.75	16.96
465/475	Cobra Head	50,000*	0.471	22.10	23.74
487	Directional	9,500	0.117	$ 8.72	
488	Directional	22,000*	0.242	13.13	
489	Directional	50,000*	0.471	18.67	
428	Open Bottom	9,500	0.117	$ 7.55	
Metal Halide					
450	Directional	12,000*	0.150	$13.75	
451	Directional	32,000*	0.350	19.46	
452	Directional	107,800*	1.080	40.58	

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 35.1
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 35.1

Standard Rate — ST. LT.
Street Lighting Service

UNDERGROUND SERVICE

FURNISHED EQUIPMENT: Street lighting equipment furnished hereunder shall consist of appropriate size decorative poles and fixtures for the lamps being used, 200 feet of underground conductor, protective equipment, controls and transformers. The Company will install, own, operate and maintain the entire street lighting system, including conductor, decorative poles, fixtures, and lamp replacements. The Customer shall pay the rate as shown plus, at the time of installation, pay to the Company the amount to cover the additional cost of underground over the equivalent overhead street lighting circuitry.

RATE

TYPE OF POLE AND FIXTURE	APPROX. LUMENS	kW RATING	MONTHLY CHARGE
HIGH PRESSURE SODIUM			
Acorn (Decorative Pole)	4,000	0.060	$12.77
Acorn (Historic Pole)	4,000	0.060	$19.16
Acorn (Decorative Pole)	5,800	0.083	$13.86
Acorn (Historic Pole)	5,800	0.083	$20.14
Acorn (Decorative Pole)	9,500	0.117	$14.39
Acorn (Historic Pole)	9,500	0.117	$20.78
Colonial	4,000	0.060	$ 8.93
Colonial	5,800	0.083	$ 9.93
Colonial	9,500	0.117	$10.35
Coach	5,800	0.083	$29.24
Coach	9,500	0.117	$29.65
Contemporary	5,800	0.083	$15.66
Contemporary	9,500	0.117	$18.19
Contemporary	22,000	0.242	$22.11
Contemporary	50,000	0.471	$28.13
Granville	16,000	0.181	$51.00
Granville Accessories:			
Single Crossarm Bracket*			$17.78
Twin Crossarm Bracket (includes 1 fixture)			$19.79
24 Inch Banner Arm			$ 3.09
24 Inch Clamp Banner Arm			$ 4.26
18 Inch Banner Arm			$ 2.84
18 Inch Clamp On Banner Arm			$ 3.52
Flagpole Holder			$ 1.31
Post-Mounted Receptacle			$18.46
Base-Mounted Receptacle			$17.81
Additional Receptacles**			$ 2.52
Planter			$ 4.28
Clamp On Planter			$ 4.75

* For Existing Poles Only
** For 2 Receptacles on Same Pole

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 35.1

Standard Rate — LS — N
Lighting Service

OVERHEAD SERVICE (continued)

Should Customer request underground service, Customer shall make a non-refundable cash contribution prior to the time of installation, or, at the option of company, make a work contribution to Company for the difference in the installed cost of the system requested and the cost of the overhead lighting system.

Where the location of existing poles is not suitable or where there are no existing poles for mounting of lights, and Customer requests service under these conditions, Company may furnish the requested facilities at an additional charge to be determined under the Excess Facilities Rider.

UNDERGROUND SERVICE

Based on Customer's lighting choice, Company will furnish, own, install, and maintain poles, fixtures, and any necessary circuitry up to 200 feet. All poles and fixtures furnished by Company will be standard stocked materials. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for underground installation.

RATE

				Monthly Charge		
Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Fixture Only	Decorative Smooth	Historic Fluted
High Pressure Sodium						
467	Colonial	5,800	0.083		$10.47	
468	Colonial	9,500	0.117		10.92	
401/411	Acorn	5,800	0.083		$14.62	$21.24
420/430	Acorn	9,500	0.117		15.18	21.92
414	Victorian	5,800	0.083			$30.84
415	Victorian	9,500	0.117			31.27
492/476	Contemporary	5,800	0.083	$15.13	$16.58	
497/477	Contemporary	9,500	0.117	15.17	20.87	
498/478	Contemporary	22,000*	0.242	17.27	26.55	
499/479	Contemporary	50,000*	0.471	20.72	32.54	
300	Dark Sky Lantern	4,000	0.060		$22.48	
301	Dark Sky Lantern	9,500	0.117		23.44	

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 35.2

Standard Rate ST. LT.

Street Lighting Service

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

DETERMINATION OF ENERGY CONSUMPTION

The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 35.2 N

Standard Rate LS

Lighting Service

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth	Monthly Charge Historic Fluted
360	Granville	16,000	0.181		$53.79	
	Granville Accessories:					
	Twin Crossarm Bracket (includes 1 fixture)					$20.87
	24 Inch Banner Arm					3.26
	24 Inch Clamp Banner Arm					4.49
	18 Inch Banner Arm					3.00
	18 Inch Clamp Banner Arm					3.71
	Flagpole Holder					1.38
	Post-Mounted Receptacle					19.47
	Additional Post-Mounted Receptacle (Limit 1 Per Pole)					2.66
	Planter					4.51
	Clamp-On Planter					5.01

Granville units are restricted to installations and configurations for the cities of Lexington and London

Metal Halide					
490/494	Contemporary	12,000*	0.150	$14.99	$28.08
491/495	Contemporary	32,000*	0.350	21.22	34.31
493/496	Contemporary	107,800*	1.080	43.98	57.07

Customer shall make a non-refundable cash contribution prior to the time of installation, or, at the option of Company, make a work contribution to Company for the difference in the installed cost of the system requested and the cost of the conventional overhead lighting system.

Where Customer's location would require the installation of additional facilities, Company may furnish, own, and maintain the requested facilities at an additional charge per month to be determined under the Excess Facilities Rider.

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill. Billing for this service to be made a part of bill rendered for other electric service.

DETERMINATION OF ENERGY CONSUMPTION

The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

The proposed KU Lighting Service Rate LS is contained on four pages instead of the current three pages of Street Lighting Rate ST. LT.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice to the other when additional facilities are required. Cancellation by Customer prior to the initial five-year term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the original five (5) year term.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.
2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults. Company shall initiate service corrections within two (2) business days after such notification by Customer.
3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.
4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.
5. If any permit is required from any municipal or other governmental authority with respect to installation and use of any of the lighting units provided hereunder, Company will seek such permits, but the ultimate responsibility belongs with Customer
6. If Customer requests the removal of an existing lighting system, including, but not limited to, fixtures, poles, or other supporting facilities that were in service less than twenty years, and requests installation of replacement lighting within 5 years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.
7. Temporary suspension of lighting service is not permitted. Upon permanent discontinuance of service, lighting units and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

Kentucky Utilities Company

P.S.C. No. 15, Third Revision of Original Sheet No. 36
Canceling P.S.C. No. 15, Second Revision of Original Sheet No. 36

Standard Rate — P.O. LT.
Private Outdoor Lighting

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this schedule is offered, under the conditions set out hereinafter, for lighting applications on private property such as, but not limited to, residential, commercial and industrial plant site or parking lot, other commercial area lighting, etc. to Customers now receiving electric service from the Company at the same location. Service will be provided under written contract signed by Customer prior to service commencing, when facilities are required other than fixture(s).

RATE
OVERHEAD SERVICE [Fixture Only]
Based on lighting choice, Company will furnish and install the lighting unit complete with lamp, fixture, photoelectric control and mast arm (cobra head).

TYPE OF FIXTURE	APPROX. LUMENS	kW RATING	MONTHLY CHARGE
High Pressure Sodium			
Cobra Head	22,000*	0.242	$13.04
Cobra Head	50,000*	0.471	20.95
Directional	9,500	0.117	8.27
Directional	22,000*	0.242	12.45
Directional	50,000*	0.471	17.70
Open Bottom	5,800	0.083	6.72
Open Bottom	9,500	0.117	7.16

Mercury Vapor

Mercury Vapor is restricted to those fixtures in service. Upon failure, exiting fixtures will either be removed from service or replaced with available lighting at the customer's option.

Cobra Head	20,000	0.453	$12.57
Open Bottom	7,000	0.207	$ 9.69

Restricted Special Lighting

Service under these rates is restricted to those special lighting customers (bill code 408 and 409) in service as of August 1, 2010. Upon failure, existing Mercury Vapor fixtures will either be removed from service or replaced with available lighting at the customer's option.

Cobra Head (Mercury Vapor)	20,000	0.453	$ 7.85
Cobra Head (High Pressure Sodium)	50,000	0.471	$10.25

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 36

Standard Rate — RLS
Restricted Lighting Service N

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate schedule is restricted to those lighting fixtures/poles in service as of August 1, 2012, except where a spot replacement maintains the continuity of multiple fixtures/poles comprising a neighborhood lighting system. Spot placement of restricted fixtures/poles is contingent on the restricted fixtures/poles being available from manufacturers. Spot replacement of restricted units will be made under the terms and conditions provided for under non-restricted Lighting Service Rate LS.

In the event restricted fixtures/poles fail and replacements are unavailable, Customer will be given the choice of having Company remove the failed fixture/pole or replacing the failed fixture/pole with other available fixture/pole.

OVERHEAD SERVICE
Based on Customer's lighting choice, Company has furnished, installed, and maintained the lighting unit complete with lamp, fixture, photoelectric control, mast arm, and, if needed, up to 150 feet of conductor per fixture on existing wood poles (fixture only). Company has, upon request, furnished poles, of Company's choosing, together with overhead wiring and all other equipment mentioned for overhead service.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Fixture Only	Monthly Charge: Fixture and Pole
High Pressure Sodium					
461/471	Cobra Head	4,000	0.060	$ 7.31	$10.29
409	Cobra Head	50,000	0.471	10.81	
426	Open Bottom	5,800	0.083	7.09	
Metal Halide					
454	Directional	12,000	0.150		$18.21
455	Directional	32,000	0.350		23.92
459	Directional	107,800	1.080		45.05
Mercury Vapor					
446/456	Cobra Head	7,000	0.207	$ 9.20	$11.54
447/457	Cobra Head	10,000	0.294	10.85	12.93
448/458	Cobra Head	20,000	0.453	12.19	14.49
404	Open Bottom	7,000	0.207	10.22	
Incandescent					
421	Tear Drop	1,000	0.102	$ 3.25	
422	Tear Drop	2,500	0.201	4.31	
424/434	Tear Drop	4,000	0.327	6.41	$ 7.38
425	Tear Drop	6,000	0.447	8.55	

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 36.1
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 36.1

Standard Rate — P.O. LT.
Private Outdoor Lighting

ADDITIONAL FACILITIES

The Company will furnish a complete standard or directional fixture with appropriate mast arm on existing poles with available secondary voltage of 120/240. All facilities required by Company will be standard stocked material. The above rates for OVERHEAD SERVICE contemplate installation on an existing wood pole and, if needed, up to 150 feet of conductor.

Where the location of existing poles is not suitable or where there are no existing poles or adequate facilities for mounting of lights, and the Customer requests service under these conditions, the Company may furnish the required facilities at an additional charge based upon the application of the monthly rate set forth in the Excess Facilities rider applied to the current cost of the facilities as periodically updated.

UNDERGROUND SERVICE

Based on lighting choice, Company will furnish and install the lighting unit complete with lamp, fixture, photoelectric control, and aluminum pole.

TYPE OF POLE AND FIXTURE	APPROX. LUMENS	kW RATING	MONTHLY CHARGE
High Pressure Sodium			
Acorn Decorative	4,000	0.060	$12.77
Acorn Historic	4,000	0.060	$19.16
Acorn Decorative	5,800	0.083	$13.86
Acorn Historic	5,800	0.083	$20.14
Acorn Decorative	9,500	0.117	$14.39
Acorn Historic	9,500	0.117	$20.78
Colonial	4,000	0.060	$ 8.93
Colonial	5,800	0.083	$ 9.93
Colonial	9,500	0.117	$10.35
Coach	5,800	0.083	$29.24
Coach	9,500	0.117	$29.65
Contemporary	5,800	0.083	$21.81
Additional Fixture	5,800	0.083	$14.35
Contemporary	9,500	0.117	$21.85
Additional Fixture	9,500	0.117	$14.38
Contemporary	22,000*	0.242	$27.84
Additional Fixture	22,000*	0.242	$16.37
Contemporary	50,000*	0.471	$31.12
Additional Fixture	50,000*	0.471	$19.65

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 36.1

Standard Rate — RLS — N
Restricted Lighting Service

OVERHEAD SERVICE (continued)

Where the location of existing poles was not suitable, or where there were no existing poles for mounting of lights, and Customer requested service under these conditions, Company may have furnished the requested facilities at an additional charge determined under the Excess Facilities Rider.

UNDERGROUND SERVICE

Based on Customer's lighting choice, Company has furnished, installed, and maintained the lighting unit complete with lamp, fixture, photoelectric control, mast arm, and, if needed, up to 200 feet of conductor per fixture on appropriate poles.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Wood Pole	Monthly Charge: Decorative Smooth	Monthly Charge: Historic Fluted
Metal Halide						
460	Directional	12,000	0.150		$26.84	
469	Directional	32,000	0.350		32.55	
470	Directional	107,800	1.080		53.67	
High Pressure Sodium						
440/410	Acorn	4,000	0.060		$13.47	$20.21
466	Colonial	4,000	0.060		$ 9.42	
412	Coach	5,800	0.083		$30.84	
413	Coach	9,500	0.117		31.27	

DUE DATE OF BILL

Payment is due within twelve (12) calendar days from the date of the bill. Billing for this service to be made a part of the bill rendered for other electric service.

DETERMINATION OF ENERGY CONSUMPTION

The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 36.2
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 36.2

Standard Rate — P.O. LT.
Private Outdoor Lighting

TYPE OF POLE AND FIXTURE	APPROX. LUMENS	kW RATING	MONTHLY CHARGE
High Pressure Sodium (Continued)			
Granville	16,000	0.181	$51.00

Granville Accessories:	MONTHLY CHARGE
Single Crossarm Bracket (Existing Poles Only)	$17.78
Twin Crossarm Bracket	19.79
24 Inch Banner Arm	3.09
24 Inch Clamp Banner Arm	4.26
18 Inch Banner Arm	2.84
18 Inch Clamp Banner Arm	3.52
Flagpole Holder	1.31
Post-Mounted Receptacle	18.46
Base-Mounted Receptacle	17.81
Additional Receptacle (2 Receptacles on Same Pole)	2.52
Planter	4.28
Clamp On Planter	4.75

For UNDERGROUND SERVICE where secondary voltage of 120/240 is available, Company will furnish, own, and maintain poles, fixtures and any necessary circuitry up to 200 feet. All poles and fixtures furnished by Company will be standard stocked materials. Where Customer's location would require the installation of additional facilities, Company may furnish, own, and maintain the requested facilities at an additional charge per month to be determined by Company. Such charges are subject to change by Company upon 30 days prior written notice.

Customer is to pay the monthly rate plus any additional charge determined above plus provide all ditching, back-filling, and repaving/seeding/sodding as necessary and provide, own, and maintain all conduit. Company may, at Customer's request, provide all ditching, back-filling, and repaving/seeding/sodding as necessary for payment, in advance, of Company's cost to provide those services. Upon termination of service, the Company shall not be required to remove underground facilities.

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 36.2

Standard Rate — RLS
Restricted Lighting Service N

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice to the other when additional facilities are required. Cancellation by Customer prior to the initial five-year term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the original five (5) year term.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.
2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults, and the Company shall initiate service corrections within two (2) business days after such notification by Customer.
3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.
4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.
5. Temporary suspension of lighting service is not permitted. Upon permanent discontinuance of service, lighting units and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Standard Rate P.O. LT.

Private Outdoor Lighting

Customer Ordered Styles

Where Customer has need for non-stocked styles of poles or fixtures, Company may agree to provide the requested styles for payment, in advance, by Customer of the cost difference between the requested styles and the stock materials. Customer accepts that Company's maintenance of non-stock materials is dependent on outside vendors and that maintenance of non-stock styles may be delayed or materials unavailable.

NOTE: * NOT AVAILABLE FOR URBAN RESIDENTIAL HOME USE

METAL HALIDE COMMERCIAL AND INDUSTRIAL LIGHTING
[OVERHEAD AND UNDERGROUND]

TYPE OF POLE AND FIXTURE	APPROX. LUMENS	kW RATING	MONTHLY CHARGE
Metal Halide			
Directional Fixture Only	12,000	0.150	$13.04
Directional Fixture With Wood Pole	12,000	0.150	17.27
Directional Fixture With Direct Burial Metal Pole	12,000	0.150	25.45
Directional Fixture Only	32,000	0.350	18.45
Directional Fixture With Wood Pole	32,000	0.350	22.68
Directional Fixture With Metal Pole	32,000	0.350	30.86
Directional Fixture Only	107,800	1.080	38.48
Directional Fixture With Wood Pole	107,800	1.080	42.71
Directional Fixture With Metal Pole	107,800	1.080	50.89
Contemporary Fixture Only	12,000	0.150	14.21
Contemporary Fixture With Direct Burial Metal Pole	12,000	0.150	26.62
Contemporary Fixture Only	32,000	0.350	20.12
Contemporary Fixture With Metal Pole	32,000	0.350	32.53
Contemporary Fixture Only	107,800	1.080	41.70
Contemporary Fixture With Metal Pole	107,800	1.080	54.11

The proposed KU Restricted Lighting Service Rate RLS is contained on three pages instead of the current five pages of Private Outdoor Lighting Rate P.O. LT.

Standard Rate P.O. LT.
Private Outdoor Lighting

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL
Payment is due within twelve (12) calendar days from the date of the bill. Billing for this service to be made a part of the bill rendered for other electric service.

DETERMINATION OF ENERGY CONSUMPTION
The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff.

TERM OF CONTRACT
For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice to the other when additional facilities are required. Cancellation by Customer prior to the initial five-year term will require the Customer to pay to Company its cost of labor to install and remove facilities plus cost of non-salvable material, prorated on the basis of the remaining portion of the five-year period.

Signed contracts will not be required when the fixture(s) are placed on existing pole with a 120 volt source.

TERMS AND CONDITIONS
1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.
2. All service and necessary maintenance on the light and facilities will be performed only during regular scheduled working hours of the Company. The customer shall be responsible for reporting outages and other operating faults, and the Company will undertake to service the lighting equipment within two (2) business days after such notification by the customer.
3. The Customer shall be responsible for fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts.
4. The Company shall own and maintain all facilities required in providing this service, except as noted above.

The proposed KU Restricted Lighting Service Rate RLS is contained on three pages instead of the current five pages of Private Outdoor Lighting Rate P.O. LT.

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 37
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 37

Standard Rate LE
Lighting Energy Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to municipalities, county governments, divisions or agencies of the state or Federal governments, civic associations, and other public or quasi-public agencies for service to public street and highway lighting systems, where the municipality or other agency owns and maintains all street lighting equipment and other facilities on its side of the point of delivery of the energy supplied hereunder.

RATE
$0.05647 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

CONDITIONS OF DELIVERY
a) Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption taking into account the types of equipment served.

b) The location of the point of delivery of the energy supplied hereunder and the voltage at which such delivery is effected shall be mutually agreed upon by Company and the customer in consideration of the type and size of customer's street lighting system and the voltage which Company has available for delivery.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 37

Standard Rate LE
Lighting Energy Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to municipalities, county governments, divisions or agencies of the state or Federal governments, civic associations, and other public or quasi-public agencies for service to public street and highway lighting systems, where the municipality or other agency owns and maintains all street lighting equipment and other facilities on its side of the point of delivery of the energy supplied hereunder.

RATE
$0.05958 per kWh I

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

CONDITIONS OF DELIVERY
a) Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption taking into account the types of equipment served.

b) The location of the point of delivery of the energy supplied hereunder and the voltage at which such delivery is effected shall be mutually agreed upon by Company and the customer in consideration of the type and size of customer's street lighting system and the voltage which Company has available for delivery.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Third Revision of Original Sheet No. 38
Cancelling P.S.C. No. 15, Second Revision of Original Sheet No. 38

Standard Rate — TE
Traffic Energy Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to municipalities, county governments, divisions of the state or Federal governments or any other governmental agency for service on a 24-hour all-day every-day basis, where the governmental agency owns and maintains all equipment on its side of the point of delivery of the energy supplied hereunder. In the application of this rate each point of delivery will be considered as a separate customer.

This service is limited to traffic control devices including, signals, cameras, or other traffic lights and electronic communication devices.

RATE

Basic Service Charge:	$3.14 per delivery per month
Plus an Energy Charge of:	$0.07182 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

CONDITIONS OF SERVICE
1. Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption, taking into account the size and characteristics of the load, or on meter readings obtained from a similar installation.
2. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and the customer. Where attachment of Customer's devices is made to Company facilities, Customer must have an attachment agreement with Company.
3. Loads not operated on an all-day every-day basis will be served under the appropriate rate.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 38

Standard Rate — TE
Traffic Energy Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to municipalities, county governments, divisions of the state or Federal governments or any other governmental agency for service on a 24-hour all-day every-day basis, where the governmental agency owns and maintains all equipment on its side of the point of delivery of the energy supplied hereunder. In the application of this rate each point of delivery will be considered as a separate customer.

This service is limited to traffic control devices including, signals, cameras, or other traffic lights and electronic communication devices.

RATE

Basic Service Charge:	$3.25 per delivery per month	I
Plus an Energy Charge of:	$0.07614 per kWh	I

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

CONDITIONS OF SERVICE
1. Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption, taking into account the size and characteristics of the load, or on meter readings obtained from a similar installation.
2. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and the customer. Where attachment of Customer's devices is made to Company facilities, Customer must have an attachment agreement with Company.
3. Loads not operated on an all-day every-day basis will be served under the appropriate rate.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 39
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 39

Standard Rate — DSK

Dark Sky Friendly

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
To any customer in accordance with the special terms and conditions set forth herein.

CHARACTER OF SERVICE
This rate schedule covers electric lighting service for the illumination of streets, driveways, yards, lots and other outdoor areas. Company will provide, own and maintain the lighting equipment, as hereinafter described, and will furnish the electrical energy to operate such equipment.

RATES

Type Of Fixture And Pole	Lumen Output (Approximate)	Load/Light In kW	Monthly Rate Per Light
High Pressure Sodium			
DSK Lantern	4,000	.050	$21.31
DSK Lantern	9,500	.100	$22.22

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF ENERGY CONSUMPTION
The kilowatt-hours will be as set forth on Sheet No. 67 of this tariff.

SPECIAL TERMS AND CONDITIONS

1. Based on lighting choice, Company will furnish and install the lighting unit complete with pole, mast arm (if applicable), control device, lamp, and fixture. All lighting units, poles and conductors shall be standard, stocked material and shall remain the property of Company. Company shall have access to the same for maintenance, inspection, and all other proper purposes.
2. Customer will be responsible for ditching, back-filling, seeding, and/or repaving, as necessary, and provide, own, and maintain all conduit.
3. Charges listed under RATE are based on a normal installation whereby the Company will provide up to 200 feet of conductor per unit where Company has underground distribution facilities with secondary 120/240 voltage available. Company may provide underground lighting service in localities served through overhead facilities when, in its judgment, it is practicable to do so. Company may decline to install equipment and provide service in locations deemed by Company as unsuitable for underground installation. If additional

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

The current KU Dark Sky Friendly Rate DSK is proposed to be included in the proposed KU Lighting Service Rate LS.

Standard Rate DSK

Dark Sky Friendly

SPECIAL TERMS AND CONDITIONS (continued)

facilities are required, Customer shall make a non-refundable cash advance equivalent to the installed cost of such excess facilities.

4. Company shall have the right to make other attachments and to further extend the conductors when necessary for the further extension of its electric service.

5. If any permit is required from municipal or other governmental authority with respect to the installation and use of any of the lighting units served hereunder, it will be the responsibility of Customer to obtain such permit.

6. All servicing and maintenance will be performed only during regular schedule working hours of Company. Customer shall be responsible for reporting outages and other operating faults, and Company will undertake to service the lighting equipment within two (2) business days after such notification by Customer.

7. Customer will exercise proper care to protect the property of Company on Customer's premises and, in the event of loss or damage to Company's property arising from the negligence of Customer, the cost of the necessary repair or replacement shall be paid by Customer. Company may decline to provide service or continue service in locations where, in Company's judgment, such equipment will be subject to unusual hazards or risk of damage.

8. Contracts for this service shall have a minimum fixed term of five (5) years, and shall continue from month to month after such minimum fixed term until terminated by either party giving thirty days notice to the other. Company shall have the right at any time to discontinue service for non-payment of bills or other causes as set forth in its Terms and Conditions.

9. Should Customer choose to terminate service prior to completion of the initial five (5) year term, and no other customer assumes the responsibility, Customer shall reimburse Company the cost associated with providing service under this tariff for installation plus removal less salvable material prorated over the remaining portion of the initial five (5) year term. Company may require this amount in a refundable deposit from Customer.

10. If Customer requests the removal of an existing lighting unit(s), pole(s), or supporting facilities, that were in service for less than twenty (20) years, and then requests the installation of new lighting within two (2) years of removal, Customer will reimburse Company the cost associated with providing service to the original lighting for installation plus removal less salvable material prorated over the twenty (20) year term remaining at the time of removal.

11. Upon permanent discontinuance of service, lighting units and other equipment associated with providing service under this tariff, except underground facilities, will be removed.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto except as noted above.

Date of Issue: September 24, 2010
Date Effective: With Bills Rendered On and After October 28, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

The current KU Dark Sky Friendly Rate DSK is proposed to be included in the proposed KU Lighting Service Rate LS.

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 40

Standard Rate CTAC

Cable Television Attachment Charges

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Where Company is willing to permit the attachments of cables, wires and appliances to its poles where, in Company's judgment, such attachments will not interfere with its electric service requirements and other prior licensees using Company's poles. Attachments will be permitted upon execution by both parties of a Cable Television Attachment Agreement supplied by Company.

ATTACHMENT CHARGE
$5.40 per year for each attachment to pole.

BILLING
Attachment Charges to be billed semi-annually based on the number of pole attachments being maintained on December 1 and June 1. Provided, however, that should the Agreement be terminated in accordance with the terms of the said Agreement, the Attachment Charges will be prorated to the date of such termination. Payment will be due within thirty (30) days from date of bill. Non-payment of bills shall constitute a default of the Agreement.

TERM OF AGREEMENT
The Cable Television Attachment Agreement shall become effective upon execution by both parties and shall continue in effect for not less than one (1) year, subject to provisions contained in the agreement. At any time thereafter, the Customer may terminate the agreement by giving not less than six (6) months' prior written notice. Upon termination of the agreement, Customer shall immediately remove its cables, wire, appliances and all other attachments from all poles of Company.

TERMS AND CONDITIONS OF POLE ATTACHMENTS
Pole attachments shall be permitted in accordance with this Schedule. Company's Terms and Conditions shall be applicable, to the extent they are not in conflict with or inconsistent with, the special provisions of this Schedule.

Upon written Agreement, Company is willing to permit, to the extent it may lawfully do so, the attachment of cables, wires and appliances to its poles by a cable television system operator, hereinafter "Customer," where, in its judgment, such use will not interfere with its electric service requirements and other prior licensees using Company's poles, including consideration of economy and safety, in accordance with this schedule approved by the Public Service Commission. The Terms and Conditions applicable to such service are as follows:

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 40

Standard Rate CTAC

Cable Television Attachment Charges

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Where Company is willing to permit the attachments of cables, wires and appliances to its poles where, in Company's judgment, such attachments will not interfere with its electric service requirements and other prior licensees using Company's poles. Attachments will be permitted upon execution by both parties of a Cable Television Attachment Agreement supplied by Company.

ATTACHMENT CHARGE
$10.01 per year for each attachment to pole. I

BILLING
Attachment Charges to be billed semi-annually based on the number of pole attachments being maintained on December 1 and June 1. Provided, however, that should the Agreement be terminated in accordance with the terms of the said Agreement, the Attachment Charges will be prorated to the date of such termination. Payment will be due within thirty (30) days from date of bill. Non-payment of bills shall constitute a default of the Agreement.

TERM OF AGREEMENT
The Cable Television Attachment Agreement shall become effective upon execution by both parties and shall continue in effect for not less than one (1) year, subject to provisions contained in the agreement. At any time thereafter, the Customer may terminate the agreement by giving not less than six (6) months' prior written notice. Upon termination of the agreement, Customer shall immediately remove its cables, wire, appliances and all other attachments from all poles of Company.

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Pole attachments shall be permitted in accordance with this Schedule. Company's Terms and Conditions shall be applicable, to the extent they are not in conflict with or inconsistent with, the special provisions of this Schedule.

Upon written Agreement, Company is willing to permit, to the extent it may lawfully do so, the attachment of cables, wires and appliances to its poles by a cable television system operator, hereinafter "Customer," where, in its judgment, such use will not interfere with its electric service requirements and other prior licensees using Company's poles, including consideration of economy and safety, in accordance with this schedule approved by the Public Service Commission. The Terms and Conditions applicable to such service are as follows:

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 40.1

Standard Rate CTAC

Cable Television Attachment Charges

1. ATTACHMENT APPLICATIONS AND PERMITS
   Before making attachment to any pole or poles of Company, Customer shall make application and receive a permit therefore on a form to be supplied by Company. The information submitted by Customer with the application for a permit shall consist of drawings and associated descriptive matter which shall be adequate in all detail to enable Company to thoroughly check the proposed installation of Customer. Before the attachments are made, the permit must be approved by Company. Customer shall not build separate pole lines along existing facilities of Company and shall not place intermediate poles in spans of Company, unless authorized by Company in writing. Company shall have the right to remove unauthorized Customer attachments at Customer's expense after notice to Customer. In the event a pole attachment count does not correspond to the recorded attachment count, Customer will pay a back attachment fee for any excess attachments. The back attachment fee will be double the rate otherwise in effect over the time since last pole attachment count and shall be payable on demand.

2. PERMITTED ATTACHMENTS
   Customer shall be permitted to make only one bolt attachment for one messenger on tangent poles and two bolt attachments for two messengers on corner poles. A maximum of five individual coaxial cables may be supported by any single messenger if these cables are all attached to the messenger by suitable lashings or bindings, and so that the maximum overall dimension of the resulting cable bundle does not exceed two (2) inches. Any messenger attachment other than to tangent poles must be properly braced with guys and anchors provided by Customer to the satisfaction of Company. The use of existing Company anchors for this purpose must be specifically authorized in writing, subject to additional charge, and will not ordinarily be permitted. The use of crossarms or brackets shall not be permitted. In addition to messenger attachments, Customer will be permitted one Customer amplifier installation per pole and four service drops to be tapped on cable messenger strand and not on pole. Customer power supply installations shall be permitted, but only at pole locations specifically approved by Company. Any or all of the above are considered one attachment for billing purposes. Any additional attachments desired by Customer will be considered on an individual basis by Company, and as a separate attachment application.

3. CONSTRUCTION AND MAINTENANCE REQUIREMENTS AND SPECIFICATIONS
   Customer's cables, wires and appliances, in each and every location, shall be erected and maintained in accordance with the requirements and specifications of the National Electrical Safety Code, current edition, and Company's construction practices, or any amendments or revisions of said Code and in compliance with any rules or orders now in effect or that hereinafter may be issued by the Public Service Commission of Kentucky, or other authority having jurisdiction. In the event any of Customer's construction does not meet any of the foregoing requirements, Customer will correct same in fifteen work days after written notification. Company may make corrections and bill Customer for total costs incurred, if not corrected by Customer.

4. MAINTENANCE OF ATTACHMENTS
   Customer shall, at its own expense, make and maintain said attachments in safe condition and in thorough repair, and in a manner suitable to Company and so as not to conflict with the use of said poles by Company, or by other parties, firms, corporations, governmental units, etc., using said poles, pursuant to any license or permit by Company, or interfere with the working

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 40.1

Standard Rate CTAC

Cable Television Attachment Charges

1. ATTACHMENT APPLICATIONS AND PERMITS
   Before making attachment to any pole or poles of Company, Customer shall make application and receive a permit therefore on a form to be supplied by Company. The information submitted by Customer with the application for a permit shall consist of drawings and associated descriptive matter which shall be adequate in all detail to enable Company to thoroughly check the proposed installation of Customer. Before the attachments are made, the permit must be approved by Company. Customer shall not build separate pole lines along existing facilities of Company and shall not place intermediate poles in spans of Company, unless authorized by Company in writing. Company shall have the right to remove unauthorized Customer attachments at Customer's expense after notice to Customer. In the event a pole attachment count does not correspond to the recorded attachment count, Customer will pay a back attachment fee for any excess attachments. The back attachment fee will be double the rate otherwise in effect over the time since last pole attachment count and shall be payable on demand.

2. PERMITTED ATTACHMENTS
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Standard Rate	CTAC Cable Television Attachment Charges

use of facilities thereon or which may, from time to time, be placed thereon. Customer shall promptly at any time, at its own expense, upon written notice from Company, relocate, replace or renew its facilities placed on said poles, and transfer them to substituted poles, or perform any other work in connection with said facilities that may be required by Company but in no case longer than 30 day after date of written request. In cases of emergency, however, Company may arrange to relocate, replace or renew the facilities placed on said poles by Customer, transfer them to substituted poles or perform any other work in connection with said facilities that may be required in the maintenance, replacement, removal or relocation of said poles, the facilities thereon or which may be placed thereon, or for the service needs of Company, or its other licensees, and Customer shall, on demand, reimburse Company for the expense thereby incurred.

5. COSTS ASSOCIATED WITH ATTACHMENTS
   In the event that any pole or. poles of Company to which Customer desires to make attachments are inadequate to support the additional facilities in accordance with the aforesaid specifications, Company will indicate on the application and permit form the changes necessary to provide adequate poles and the estimated cost thereof to Customer. If Customer still desires to make the attachments, Company will replace such inadequate poles with suitable poles and Customer will, on demand, reimburse Company for the total cost of pole replacement necessary to accommodate Customer attachments, less the salvage value of any pole that is removed, and the expense of transferring Company's facilities from the old to the new poles. Where Customer desired attachments can be accommodated on pre-sent poles of Company by rearranging Company's facilities thereon, Customer will compensate Company for the full expense incurred in completing such rearrangements, within ten days after receipt of Company's invoice for such expense. Customer will also, on demand, reimburse the owner or owners of other facilities attached to said poles for any expense incurred by it or them in transferring or rearranging said facilities. In the event Customer makes an unauthorized attachment which necessitates rearrangements when discovered, then Customer shall pay on demand twice the expense incurred in completing such rearrangements.

6. MAINTENANCE AND OPERATION OF COMPANY'S FACILITIES
   Company reserves to itself, its successors and assigns, the right to maintain its poles and to operate its facilities thereon in such manner as will, in its own judgment, best enable it to fulfill its electric service requirements, but in accordance with the specifications herein before referred to. Company shall not be liable to Customer for any interruption to service to Customer's subscribers or for interference with the operation of the cables, wires and appliances of Customer arising in any manner out of the use of Company's poles hereunder.

7. FRANCHISES AND EASEMENTS
   Customer shall submit to Company evidence, satisfactory to Company, of Customer's authority to erect and maintain Customer's facilities within public streets, highways and other thoroughfares within the above described territory which is to be served and shall secure any necessary consent by way of franchise or other satisfactory license, permit or authority, acceptable to Company from State, County or municipal authorities or from the owners of property where necessary to construct and maintain facilities at the locations of poles of Company which it desires to use. Customer must secure its own easement rights on private property. Customer must, regardless of authority received or franchises given by governmental

Standard Rate	CTAC Cable Television Attachment Charges

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Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 40.3

Standard Rate | CTAC
Cable Television Attachment Charges

agencies, conform to all requirements of Terms and Conditions with regard to Company's property. Company's approval of attachments shall not constitute any representation or warranty by Company to Customer regarding Customer's right to occupy or use any public or private right-of-way.

8. INSPECTION OF FACILITIES
Company reserves the right to inspect each new installation of Customer on its poles and in the vicinity of its lines or appliances and to make periodic inspections, every two (2) years or more often as plant conditions warrant of the entire plant of Customer. Such inspections, made or not, shall not operate to relieve Customer of any responsibility, obligation or liability.

9. PRECAUTIONS TO AVOID FACILITY DAMAGE
Customer shall exercise precautions to avoid damage to facilities of Company and of others supported on said poles; and shall assume all responsibility of any and all loss for such damage caused by it. Customer shall make an immediate report to Company of the occurrence of any damage and shall reimburse Company for the expense incurred in making repairs.

10. INDEMNITIES AND INSURANCE
Customer shall defend, indemnify and save harmless Company from any and all damage, loss, claim, demand, suit, liability, penalty or forfeiture of every kind and nature-including but not limited to costs and expenses of defending against the same and payment of any settlement or judgment therefore, by reason of (a) injuries or deaths to persons, (b) damages to or destructions of properties, (c) pollutions, contaminations of or other adverse effects on the environment or (d) violations of governmental laws, regulations or orders whether suffered directly by Company it-self or indirectly by reason of claims, demands or suits against it by third parties, resulting or alleged to have resulted from acts or omissions of Customer, its employees, agents, or other representatives or from their presence on the premises of Company, either solely or in concurrence with any alleged joint negligence of Company.

Customer shall provide and maintain in an Insurance Company(s) authorized to do business in the Commonwealth of Kentucky, the following:

(a) Insurance protection for Customer employees to the extent required by the Workmen's Compensation Law of Kentucky and, where same is not applicable or if necessary to provide a defense for Company, Employer's Liability Protection (covering both Company and Customer) for Customer employees for no less than $100,000.00 per employee.

(b) Public Liability and Business Liability insurance with a minimum limit of $500,000.00 for each person injured and with a minimum total limit of $1,000,000.00 for each accident and a minimum limit of $100,000.00 for property damage for each accident.

(c) Public Liability and Property Damage insurance on all automotive equipment used by Customer on job to the extent of the amounts for Public Liability and Property Damage insurance set out in the preceding Paragraph (b).

(d) In the event that work covered by the Agreement includes work to be done in places or areas where the Maritime Laws are in effect, then and in that event additional insurance protection to the limits in Paragraph (b) above for liability arising out of said Maritime Laws.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 40.3

Standard Rate | CTAC
Cable Television Attachment Charges

agencies, conform to all requirements of Terms and Conditions with regard to Company's property. Company's approval of attachments shall not constitute any representation or warranty by Company to Customer regarding Customer's right to occupy or use any public or private right-of-way.

8. INSPECTION OF FACILITIES
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10. INDEMNITIES AND INSURANCE
Customer shall defend, indemnify and save harmless Company from any and all damage, loss, claim, demand, suit, liability, penalty or forfeiture of every kind and nature-including but not limited to costs and expenses of defending against the same and payment of any settlement or judgment therefore, by reason of (a) injuries or deaths to persons, (b) damages to or destructions of properties, (c) pollutions, contaminations of or other adverse effects on the environment or (d) violations of governmental laws, regulations or orders whether suffered directly by Company it-self or indirectly by reason of claims, demands or suits against it by third parties, resulting or alleged to have resulted from acts or omissions of Customer, its employees, agents, or other representatives or from their presence on the premises of Company, either solely or in concurrence with any alleged joint negligence of Company.

Customer shall provide and maintain in an Insurance Company(s) authorized to do business in the Commonwealth of Kentucky, the following:

(a) Insurance protection for Customer employees to the extent required by the Workmen's Compensation Law of Kentucky and, where same is not applicable or if necessary to provide a defense for Company, Employer's Liability Protection (covering both Company and Customer) for Customer employees for no less than $100,000.00 per employee.

(b) Public Liability and Business Liability insurance with a minimum limit of $500,000.00 for each person injured and with a minimum total limit of $1,000,000.00 for each accident and a minimum limit of $100,000.00 for property damage for each accident.

(c) Public Liability and Property Damage insurance on all automotive equipment used by Customer on job to the extent of the amounts for Public Liability and Property Damage insurance set out in the preceding Paragraph (b).

(d) In the event that work covered by the Agreement includes work to be done in places or areas where the Maritime Laws are in effect, then and in that event additional insurance protection to the limits in Paragraph (b) above for liability arising out of said Maritime Laws.

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(e) In the event the work covers fixed wing aircraft, rotor lift, lighter than air aircraft or any other form of aircraft, appropriate insurance will be carried affording protection to the limits prescribed in the preceding Paragraph (b).

(f) In the event the work covers blasting, explosives or operations underground, in trenches or other excavations, appropriate insurance will be carried affording protection to the limits prescribed in the preceding Paragraph (b), together with products hazard and completed operations insurance where applicable, affording protection to the limits above prescribed. Customer's liability insurance shall be written to eliminate XCU exclusions. Said insurance is to be kept in force for not less than one year after cancellation of the Agreement.

Before starting work, Customer shall furnish to Company a certificate(s) of insurance satisfactory to Company, evidencing the existence of the insurance required by the above provisions, and this insurance may not be canceled for any cause without sixty (60) days advance written notice being first given Company; provided, that failure of Company to require Customer to furnish any such certificate(s) shall not constitute a waiver by Company of Customer's obligation to maintain insurance as provided herein.

Each policy required hereunder shall contain a contractual endorsement written as follows: "The insurance provided herein shall also be for the benefit of Kentucky Utilities Company so as to guarantee, within the policy limits, the performance by the named insured of the indemnity provisions of the Cable Television Attachment Agreement between the named insured and Kentucky Utilities Company. This insurance may not be canceled for any cause without sixty (60) days advance written notice being first given to Kentucky Utilities Company."

11. ATTACHMENT REMOVAL AND NOTICES
Customer may at any time voluntarily remove its attachments from any pole or poles of Company, but shall immediately give Company written notice of such removal on a form to be supplied by Company. No refund of any attachment charge will be due on account of such voluntary removal.

12. FORBIDDEN USE OF POLES
Prior to Customer's initial attachment, Company reserves the right due to engineering design requirements to refuse use by Customer of certain or specific poles or structures (such as normal transmission routes). Upon notice from Company to Customer that the use of any pole or poles is forbidden by municipal or other public authorities or by property owners, the permit covering the use of such pole or poles shall immediately terminate and Customer shall remove its facilities from the affected pole or poles at once. No refund of any attachment charge will be due on account of any removal resulting from such forbidden use.

13. NON-COMPLIANCE
If Customer shall fail to comply with any of the provisions of these Rules and Regulations or Terms and Conditions or default in any of its obligations under these Rules and Regulations or Terms and Conditions and shall fail within thirty (30) days after written notice from Company to correct such default or non-compliance, Company may, at its option, forthwith terminate the Agreement or the permit covering the poles as to which such default or non- compliance shall have occurred, by giving written notice to Customer of said termination. No refund of any rental will be due on account of such termination.

(e) In the event the work covers fixed wing aircraft, rotor lift, lighter than air aircraft or any other form of aircraft, appropriate insurance will be carried affording protection to the limits prescribed in the preceding Paragraph (b).

(f) In the event the work covers blasting, explosives or operations underground, in trenches or other excavations, appropriate insurance will be carried affording protection to the limits prescribed in the preceding Paragraph (b), together with products hazard and completed operations insurance where applicable, affording protection to the limits above prescribed. Customer's liability insurance shall be written to eliminate XCU exclusions. Said insurance is to be kept in force for not less than one year after cancellation of the Agreement.

Before starting work, Customer shall furnish to Company a certificate(s) of insurance satisfactory to Company, evidencing the existence of the insurance required by the above provisions, and this insurance may not be canceled for any cause without sixty (60) days advance written notice being first given Company; provided, that failure of Company to require Customer to furnish any such certificate(s) shall not constitute a waiver by Company of Customer's obligation to maintain insurance as provided herein.

Each policy required hereunder shall contain a contractual endorsement written as follows: "The insurance provided herein shall also be for the benefit of Kentucky Utilities Company so as to guarantee, within the policy limits, the performance by the named insured of the indemnity provisions of the Cable Television Attachment Agreement between the named insured and Kentucky Utilities Company. This insurance may not be canceled for any cause without sixty (60) days advance written notice being first given to Kentucky Utilities Company."

11. ATTACHMENT REMOVAL AND NOTICES
Customer may at any time voluntarily remove its attachments from any pole or poles of Company, but shall immediately give Company written notice of such removal on a form to be supplied by Company. No refund of any attachment charge will be due on account of such voluntary removal.

12. FORBIDDEN USE OF POLES
Prior to Customer's initial attachment, Company reserves the right due to engineering design requirements to refuse use by Customer of certain or specific poles or structures (such as normal transmission routes). Upon notice from Company to Customer that the use of any pole or poles is forbidden by municipal or other public authorities or by property owners, the permit covering the use of such pole or poles shall immediately terminate and Customer shall remove its facilities from the affected pole or poles at once. No refund of any attachment charge will be due on account of any removal resulting from such forbidden use.

13. NON-COMPLIANCE
If Customer shall fail to comply with any of the provisions of these Rules and Regulations or Terms and Conditions or default in any of its obligations under these Rules and Regulations or Terms and Conditions and shall fail within thirty (30) days after written notice from Company to correct such default or non-compliance, Company may, at its option, forthwith terminate the Agreement or the permit covering the poles as to which such default or non-compliance shall have occurred, by giving written notice to Customer of said termination. No refund of any rental will be due on account of such termination.

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 40.5

Standard Rate CTAC
Cable Television Attachment Charges

14. WAIVERS
Failure to enforce or insist upon compliance with any of these Rules and Regulations or Terms and Conditions or the Agreement shall not constitute a general waiver or relinquishment thereof, but the same shall be and remain at all times in full force and effect.

15. USE OF COMPANY'S FACILITIES BY OTHERS
Nothing herein contained shall be construed as affecting the rights or privileges previously conferred by Company, by contract or otherwise, to others, not parties to the Agreement, to use any poles covered by the Agreement; and Company shall have the right to continue and to extend such rights or privileges. The attachment privileges herein granted shall at all times be subject to such existing contracts and arrangements.

16. ASSIGNMENT
Customer shall not assign, transfer or sublet the privileges hereby granted and/or provided in the Agreement without the prior consent in writing of Company.

17. PROPERTY RIGHTS
No use, however extended, of Company poles under the Agreement shall create or vest in Customer any ownership or property rights in said poles, but Customer shall be and remain a customer only. Nothing herein contained shall be construed to compel Company to maintain any of said poles for a period longer than demanded by its electric service requirements.

18. FAILURE TO PROCEED
Customer agrees to proceed as expeditiously as practical with the work of providing the television cable service to the area described in the Agreement. Within ninety (90) days from the date of the Agreement, Customer shall make progress reasonably satisfactory to Company in the installation of its facilities or shall demonstrate, to the reasonable satisfaction of Company, its ability to proceed expeditiously.

19. TERMINATION
Upon termination of the Agreement in accordance with any of its terms, Customer shall immediately remove its cables, wires and appliances from all poles of Company. If not removed, Company shall have the right to remove them at the cost and expense of Customer.

20. SECURITY
Customer shall furnish bond for the purposes hereinafter specified as follows:

(a) during the period of Customer's initial installation of its facilities and at the time of any expansion involving more than seventy-five (75) poles, a bond in the amount of $2,000 for each 100 poles (or fraction thereof) to which Customer intends to attach its facilities;
(b) following the satisfactory completion of Customer's initial installation, the amount of bond shall be reduced to $1,000 for each 100 poles (or fraction thereof);
(c) after Customer has been a customer of Company pursuant to the Agreement and is not in default thereunder for a period of three years, the bond shall be reduced to $500 for each 100 poles (or fraction thereof).

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 40.5

Standard Rate CTAC
Cable Television Attachment Charges

14. WAIVERS
Failure to enforce or insist upon compliance with any of these Rules and Regulations or Terms and Conditions or the Agreement shall not constitute a general waiver or relinquishment thereof, but the same shall be and remain at all times in full force and effect.

15. USE OF COMPANY'S FACILITIES BY OTHERS
Nothing herein contained shall be construed as affecting the rights or privileges previously conferred by Company, by contract or otherwise, to others, not parties to the Agreement, to use any poles covered by the Agreement; and Company shall have the right to continue and to extend such rights or privileges. The attachment privileges herein granted shall at all times be subject to such existing contracts and arrangements.

16. ASSIGNMENT
Customer shall not assign, transfer or sublet the privileges hereby granted and/or provided in the Agreement without the prior consent in writing of Company.

17. PROPERTY RIGHTS
No use, however extended, of Company poles under the Agreement shall create or vest in Customer any ownership or property rights in said poles, but Customer shall be and remain a customer only. Nothing herein contained shall be construed to compel Company to maintain any of said poles for a period longer than demanded by its electric service requirements.

18. FAILURE TO PROCEED
Customer agrees to proceed as expeditiously as practical with the work of providing the television cable service to the area described in the Agreement. Within ninety (90) days from the date of the Agreement, Customer shall make progress reasonably satisfactory to Company in the installation of its facilities or shall demonstrate, to the reasonable satisfaction of Company, its ability to proceed expeditiously.

19. TERMINATION
Upon termination of the Agreement in accordance with any of its terms, Customer shall immediately remove its cables, wires and appliances from all poles of Company. If not removed, Company shall have the right to remove them at the cost and expense of Customer.

20. SECURITY
Customer shall furnish bond for the purposes hereinafter specified as follows:

(a) during the period of Customer's initial installation of its facilities and at the time of any expansion involving more than seventy-five (75) poles, a bond in the amount of $2,000 for each 100 poles (or fraction thereof) to which Customer intends to attach its facilities;
(b) following the satisfactory completion of Customer's initial installation, the amount of bond shall be reduced to $1,000 for each 100 poles (or fraction thereof);
(c) after Customer has been a customer of Company pursuant to the Agreement and is not in default thereunder for a period of three years, the bond shall be reduced to $500 for each 100 poles (or fraction thereof).

Date of Issue: June 29, 2012
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

(d) such bond shall contain the provision that it shall not be terminated prior to six (6) months' after receipt by Company of written notice of the desire of the bonding or insurance company to terminate such bond. This six (6) months' termination clause may be waived by Company if an acceptable replacement bond is received before the six (6) months has ended. Upon receipt of such termination notice, Company shall request Customer to immediately remove its cables, wires and all other facilities from all poles of Company. If Customer should fail to complete the removal of all of its facilities from the poles of Company within thirty (30) days after receipt of such request from Company, then Company shall have the right to remove them at the cost and expense of Customer and without being liable for any damage to Customer's wires, cables, fixtures or appurtenances. Such bond shall guarantee the payment of any sums which may become due to Company for rentals, inspections or work performed for the benefit of Customer under the Agreement, including the removal of attachments upon termination of the Agreement by any of its provisions.

e) Company in its sole discretion may agree in writing to accept other collateral (such as a cash deposit or an irrevocable bank letter of credit) in substitution for the bond required by, and subject to the other requirements of, this Section 22.

21. NOTICES

Any notice, or request, required by these Rules and Regulations or Terms and Conditions or the Agreement shall be deemed properly given if mailed, postage pre-paid, to Company, in the case of Company; or in the case of the Customer, to its representative designated in the Agreement. The designation of the person to be notified, and/or his address may be changed by Company or Customer at any time, or from time to time, by similar notice.

22. ADJUSTMENTS

Nothing contained herein or in any Agreement shall be construed as affecting in any way the right of Company, and Company shall at all times have the right, to unilaterally file with the Public Service Commission a change in rental charges for attachments to poles, other charges as provided for, any rule, regulation, condition or any other change required. Such change or changes to become effective upon approval of the Commission or applicable regulations or statutes, and shall constitute an amendment to the Agreement.

23. BINDING EFFECT

Subject to the provisions of Section 18 hereof, the Agreement and these Rules and Regulations or Terms and Conditions shall extend to and bind the successors and assigns of the parties hereto.

(d) such bond shall contain the provision that it shall not be terminated prior to six (6) months' after receipt by Company of written notice of the desire of the bonding or insurance company to terminate such bond. This six (6) months' termination clause may be waived by Company if an acceptable replacement bond is received before the six (6) months has ended. Upon receipt of such termination notice, Company shall request Customer to immediately remove its cables, wires and all other facilities from all poles of Company. If Customer should fail to complete the removal of all of its facilities from the poles of Company within thirty (30) days after receipt of such request from Company, then Company shall have the right to remove them at the cost and expense of Customer and without being liable for any damage to Customer's wires, cables, fixtures or appurtenances. Such bond shall guarantee the payment of any sums which may become due to Company for rentals, inspections or work performed for the benefit of Customer under the Agreement, including the removal of attachments upon termination of the Agreement by any of its provisions.

(e) Company in its sole discretion may agree in writing to accept other collateral (such as a cash deposit or an irrevocable bank letter of credit) in substitution for the bond required by, and subject to the other requirements of, this Section 20. T

21. NOTICES

Any notice, or request, required by these Rules and Regulations or Terms and Conditions or the Agreement shall be deemed properly given if mailed, postage pre-paid, to Company, in the case of Company; or in the case of the Customer, to its representative designated in the Agreement. The designation of the person to be notified, and/or his address may be changed by Company or Customer at any time, or from time to time, by similar notice.

22. ADJUSTMENTS

Nothing contained herein or in any Agreement shall be construed as affecting in any way the right of Company, and Company shall at all times have the right, to unilaterally file with the Public Service Commission a change in rental charges for attachments to poles, other charges as provided for, any rule, regulation, condition or any other change required. Such change or changes to become effective upon approval of the Commission or applicable regulations or statutes, and shall constitute an amendment to the Agreement.

23. BINDING EFFECT

Subject to the provisions of Section 16 hereof, the Agreement and these Rules and Regulations or Terms and Conditions shall extend to and bind the successors and assigns of the parties hereto. T

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 45

Standard Rate

Special Charges

The following charges will be applied uniformly throughout Company's service territory. Each charge, as approved by the Public Service Commission, reflects only that revenue required to cover associated expenses.

RETURNED PAYMENT CHARGE

In those instances where a customer renders payment to Company which is not honored upon deposit by Company, the customer will be charged $10.00 to cover the additional processing costs.

METER TEST CHARGE

Where the test of a meter is performed during normal working hours upon the written request of a customer, pursuant to 807 KAR 5:006, Section 18, and the results show the meter was not more than two percent fast, the customer will be charged $60.00 to cover the test and transportation costs.

DISCONNECT/RECONNECT SERVICE CHARGE

A charge of $25.00 will be made to cover disconnection and reconnection of electric service when discontinued for non-payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection.

Residential and general service customers may request and be granted temporary suspension of electric service. In the event of such temporary suspension, Company will make a charge of $25.00 to cover disconnection and reconnection of electric service, such charge to be made before reconnection is effected.

METER PULSE CHARGE

Where a customer desires and Company is willing to provide data meter pulses, a charge of $9.00 per month per installed set of pulse-generating equipment will be made to those data pulses. Time pulses will not be supplied.

METER DATA PROCESSING CHARGE

A charge of $2.75 per report will be made to cover the cost of processing, generating, and providing recorder metered customer with profile reports. If a customer is not recorder metered and desires to have such metering installed, the customer will pay all costs associated with installing the recorder meter.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 45

Standard Rate

Special Charges

The following charges will be applied uniformly throughout Company's service territory. Each charge, as approved by the Public Service Commission, reflects only that revenue required to cover associated expenses.

RETURNED PAYMENT CHARGE

In those instances where a customer renders payment to Company which is not honored upon deposit by Company, the customer will be charged $10.00 to cover the additional processing costs.

METER TEST CHARGE

Where the test of a meter is performed during normal working hours upon the written request of a customer, pursuant to 807 KAR 5:006, Section 18, and the results show the meter was not more than two percent fast, the customer will be charged $75.00 to cover the test and transportation costs. I

DISCONNECT/RECONNECT SERVICE CHARGE

A charge of $28.00 will be made to cover disconnection and reconnection of electric service when discontinued for non-payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection. I

Residential and general service customers may request and be granted temporary suspension of electric service. In the event of such temporary suspension, Company will make a charge of $28.00 to cover disconnection and reconnection of electric service, such charge to be made before reconnection is effected. I

METER PULSE CHARGE

Where a customer desires and Company is willing to provide data meter pulses, a charge of $15.00 per month per installed set of pulse-generating equipment will be made to those data pulses. Time pulses will not be supplied. I

METER DATA PROCESSING CHARGE

A charge of $2.75 per report will be made to cover the cost of processing, generating, and providing recorder metered customer with profile reports. If a customer is not recorder metered and desires to have such metering installed, the customer will pay all costs associated with installing the recorder meter.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 50

Standard Rate Rider — CSR10

Curtailable Service Rider 10

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to customers served under applicable power schedules who contract for not less than 1,000 kilowatts individually. The aggregate service under P.S.C. No. 15, CSR10 and CSR30 for Kentucky Utilities Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 14, CSR1 and CSR3 for Kentucky Utilities Company as of August 1, 2010.

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed three hundred and seventy-five (375) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time that may have both physical curtailments and buy-through options within the interval between the start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than ten (10) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year without a buy-through option during system reliability events. For the purposes of this rider, a system reliability event is any condition or occurrence: 1) that impairs KU and LG&E's ability to maintain service to contractually committed system load; 2) where KU and LG&E's ability to meet their compliance obligations with NERC reliability standards cannot otherwise be achieved; or 3) that KU and LG&E reasonably anticipate will last more than six hours and could require KU and LG&E to call upon automatic reserve sharing ("ARS") at some point during the event. Company may also request at its sole discretion up to 275 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements.

Curtailable load and compliance with a request for curtailment shall be measured in one of the following ways:

Option A – Customer may contract for a given amount of firm demand, as measured on a 15-minute demand basis. During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price, as applicable, shall apply to the difference in the actual kWh during any requested curtailment and the contracted firm demand multiplied by the time period (hours) of curtailment [Actual kWh – (firm kW x hours curtailed)]. The measured demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance, as measured on a 15-minute demand basis.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 50

Standard Rate Rider — CSR10

Curtailable Service Rider 10

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to customers served under applicable power schedules who contract for not less than 1,000 kilowatts individually. The aggregate service under P.S.C. No. 16, CSR10 and CSR30 for Kentucky Utilities Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 14, CSR1 and CSR3 for Kentucky Utilities Company as of August 1, 2010. T

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed three hundred and seventy-five (375) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time that may have both physical curtailments and buy-through options within the interval between the start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than ten (10) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year without a buy-through option. Company may also request at its sole discretion up to 275 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements. T

Curtailable load and compliance with a request for curtailment shall be measured in one of the following ways:

Option A -- Customer may contract for a given amount of firm demand, as measured on the demand basis of the standard rate on which Customer is billed. T During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price, as applicable, shall apply to the difference in the actual kWh during any requested curtailment and the contracted firm demand multiplied by the time period (hours) of curtailment [Actual kWh – (firm kVA x hours curtailed)]. T The measured demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance, as measured on the demand basis of the T standard rate on which Customer is billed. T

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Standard Rate Rider CSR10
Curtailable Service Rider 10

Option B – Customer may contract for a given amount of curtailable load by which Customer shall agree to reduce its demand at any time by such Designated Curtailable Load. During a request for physical curtailment, Customer shall reduce its demand to a level equal to the maximum 15-minute demand immediately prior to the curtailment less the designated curtailable load. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price shall apply to the difference in the actual kWh during any requested curtailment and the product of Customer's maximum load immediately preceding curtailment less Customer's designated curtailable load designated in the contract multiplied by the time period (hours) of a requested curtailment {Actual kWh – [(Max kW preceding – Designated Curtailable kW) x hours of requested curtailment]}. Non-compliance for each requested physical curtailment shall be the measured positive value determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) the Customer's maximum demand during such curtailment.

RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service	$ 5.40 per kW of Curtailable Billing Demand
Primary Voltage Service	$ 5.50 per kW of Curtailable Billing Demand
Non-Compliance Charge of:	$16.00 per kW

Failure of Customer to curtail when requested to do so may result in termination of service under this rider. Customer will be charged for the portion of each requested curtailment not met at the applicable standard charges. The Company and Customer may arrange to have installed, at Customer's expense, the necessary telecommunication and control equipment to allow the Company to control Customers' curtailable load. Non-compliance charges will be waived if failure to curtail is a result of failure of Company's equipment; however, non-compliance charges will not be waived if failure to curtail is a result of Customer's equipment. If arrangements are made to have telecommunication and control equipment installed, then backup arrangements must also be established in the event either Company's or Customer's equipment fails.

CURTAILABLE BILLING DEMAND

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) the Customer's measured maximum kilowatt demand during the billing period for any 15-minute interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M,(EST) and (ii) for the months October continuously through April, from 6 A.M. to 10 P.M, (EST) and (b) the firm contract demand.

For a Customer electing Option B, Curtailable Billing Demand shall be the customer Designated Curtailable Load, as described above.

Standard Rate Rider CSR10
Curtailable Service Rider 10

Option B – Customer may contract for a given amount of curtailable load by which Customer shall agree to reduce its demand at any time by such Designated Curtailable Load. During a request for physical curtailment, Customer shall reduce its demand to a level equal to the maximum demand (as T
measured on the demand basis of the standard rate on which Customer is billed) T
immediately prior to the curtailment less the designated curtailable load. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price shall apply to the difference in the actual kWh during any requested curtailment and the product of Customer's maximum load immediately preceding curtailment less Customer's designated curtailable load designated in the contract multiplied by the time period (hours) of a requested curtailment {Actual kWh – [(Max kVA preceding – Designated Curtailable kVA) x hours of requested T
curtailment]}. Non-compliance for each requested physical curtailment shall be the measured positive value determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) the Customer's maximum demand during such curtailment.

RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service	$ 2.75 per kVA of Curtailable Billing Demand	R/T
Primary Voltage Service	$ 2.80 per kVA of Curtailable Billing Demand	R/T
Non-Compliance Charge of:	$16.00 per kVA	T

Failure of Customer to curtail when requested to do so may result in termination of service under this rider. Customer will be charged for the portion of each requested curtailment not met at the applicable standard charges. The Company and Customer may arrange to have installed, at Customer's expense, the necessary telecommunication and control equipment to allow the Company to control Customers' curtailable load. Non-compliance charges will be waived if failure to curtail is a result of failure of Company's equipment; however, non-compliance charges will not be waived if failure to curtail is a result of Customer's equipment. If arrangements are made to have telecommunication and control equipment installed, then backup arrangements must also be established in the event either Company's or Customer's equipment fails.

CURTAILABLE BILLING DEMAND

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) the Customer's measured maximum kilowatt demand during the billing period for any billing T
interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M,(EST) and (ii) for the months October continuously through April, from 6 A.M. to 10 P.M, (EST) and (b) the firm contract demand.

For a Customer electing Option B, Curtailable Billing Demand shall be the customer Designated Curtailable Load, as described above.

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 50.2

Standard Rate Rider CSR10

Curtailable Service Rider 10

AUTOMATIC BUY-THROUGH PRICE

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP represents the mid-point price for natural gas ($/MMBtu) posted for the day in "Gas Daily" for Dominion—South Point and will be used for the electrical day from 12 midnight to midnight. Also the posted price for Monday or the day after a holiday is the posted price for Saturday, Sunday and the holiday.

TERM OF CONTRACT

The minimum original contract period shall be one (1) year and thereafter until terminated by giving at least six (6) months previous written notice, but Company may require that contract be executed for a longer initial term when deemed reasonably necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

When the Company requests curtailment, upon request by the Customer, the Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by the Company, the Customer shall provide to the Company a good-faith, non-binding short-term operational schedule for their facility. Upon request by the Customer, the Company will provide, once per month, to the Customer an explanation of the reasons for any request for curtailment.

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 50.2

Standard Rate Rider CSR10

Curtailable Service Rider 10

AUTOMATIC BUY-THROUGH PRICE

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP represents the mid-point price for natural gas ($/MMBtu) posted for the day in *Platts Gas Daily* for Dominion—South Point and will be used for the electrical day from 12 midnight to midnight. Also the posted price for Monday or the day after a holiday is the posted price for Saturday, Sunday and the holiday. T

TERM OF CONTRACT

The minimum original contract period shall be one (1) year and thereafter until terminated by giving at least six (6) months previous written notice, but Company may require that contract be executed for a longer initial term when deemed reasonably necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

When the Company requests curtailment, upon request by the Customer, the Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by the Company, the Customer shall provide to the Company a good-faith, non-binding short-term operational schedule for their facility. Upon request by the Customer, the Company will provide, once per month, to the Customer an explanation of the reasons for any request for curtailment.

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 51

Standard Rate Rider CSR30

Curtailable Service Rider 30

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to customers served under applicable power schedules who contract for not less than 1,000 kilowatts individually. The aggregate service under P.S.C. No. 15, CSR10 and CSR30 for Kentucky Utilities Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 14, CSR1 and CSR3 for Kentucky Utilities Company as of August 1, 2010.

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed three hundred and fifty (350) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time that may have both physical curtailments and buy-through options within the interval between the start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than thirty (30) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year without a buy-through option during system reliability events. For the purposes of this rider, a system reliability event is any condition or occurrence: 1) that impairs KU and LG&E's ability to maintain service to contractually committed system load; 2) where KU and LG&E's ability to meet their compliance obligations with NERC reliability standards cannot otherwise be achieved; or 3) that KU and LG&E reasonably anticipate will last more than six hours and could require KU and LG&E to call upon automatic reserve sharing ("ARS") at some point during the event. Company may also request at its sole discretion up to 250 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements.

Curtailable load and compliance with a request for curtailment shall be measured in one of the following ways:

Option A – Customer may contract for a given amount of firm demand, as measured on a 15-minute demand basis. During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price, as applicable, shall apply to the difference in the actual kWh during any requested curtailment and the contracted firm demand multiplied by the time period (hours) of curtailment [Actual kWh – (firm kW x hours curtailed)]. The measured demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance, as measured on a 15-minute demand basis.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 51

Standard Rate Rider CSR30

Curtailable Service Rider 30

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to customers served under applicable power schedules who contract for not less than 1,000 kilowatts individually. The aggregate service under P.S.C. No. 16 , CSR10 and CSR30 for Kentucky Utilities Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 14, CSR1 and CSR3 for Kentucky Utilities Company as of August 1, 2010. T

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed three hundred and fifty (350) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time that may have both physical curtailments and buy-through options within the interval between the start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than thirty (30) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year without a buy-through option. Company may also request at its sole discretion up to 250 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements. T

Curtailable load and compliance with a request for curtailment shall be measured in one of the following ways:

Option A -- Customer may contract for a given amount of firm demand, as measured on the demand basis of the standard rate on which Customer is billed. During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price, as applicable, shall apply to the difference in the actual kWh during any requested curtailment and the contracted firm demand multiplied by the time period (hours) of curtailment [Actual kWh – (firm kVA x hours curtailed)]. The measured demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance, as measured on the demand basis of the standard rate on which Customer is billed. T T T T

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 51.1

Standard Rate Rider | CSR30

Curtailable Service Rider 30

Option B – Customer may contract for a given amount of curtailable load by which Customer shall agree to reduce its demand at any time by such Designated Curtailable Load. During a request for physical curtailment, Customer shall reduce its demand to a level equal to the maximum 15-minute demand immediately prior to the curtailment less the designated curtailable load. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price shall apply to the difference in the actual kWh during any requested curtailment and the product of Customer's maximum load immediately preceding curtailment less Customer's designated curtailable load designated in the contract multiplied by the time period (hours) of a requested curtailment {Actual kWh – [(Max kW preceding – Designated Curtailable kW) x hours of requested curtailment]}. Non-compliance for each requested physical curtailment shall be the measured positive value determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) the Customer's maximum demand during such curtailment.

RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service	$ 4.30 per kW of Curtailable Billing Demand
Primary Voltage Service	$ 4.40 per kW of Curtailable Billing Demand
Non-Compliance Charge of:	$16.00 per kW

Failure of Customer to curtail when requested to do so may result in termination of service under this rider. Customer will be charged for the portion of each requested curtailment not met at the applicable standard charges. The Company and Customer may arrange to have installed, at Customer's expense, the necessary telecommunication and control equipment to allow the Company to control Customers' curtailable load. Non-compliance charges will be waived if failure to curtail is a result of failure of Company's equipment; however, non-compliance charges will not be waived if failure to curtail is a result of Customer's equipment. If arrangements are made to have telecommunication and control equipment installed, then backup arrangements must also be established in the event either Company's or Customer's equipment fails.

CURTAILABLE BILLING DEMAND

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) the Customer's measured maximum kilowatt demand during the billing period for any 15-minute interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M. (EST) and (ii) for the months October continuously through April, from 6 A.M. to 10 P.M, (EST) and (b) the firm contract demand.

For a Customer electing Option B, Curtailable Billing Demand shall be the customer Designated Curtailable Load, as described above.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 51.1

Standard Rate Rider | CSR30

Curtailable Service Rider 30

Option B -- Customer may contract for a given amount of curtailable load by which Customer shall agree to reduce its demand at any time by such Designated Curtailable Load. During a request for physical curtailment, Customer shall reduce its demand to a level equal to the maximum demand (as T
measured on the demand basis of the standard rate on which Customer is billed) T
immediately prior to the curtailment less the designated curtailable load. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price shall apply to the difference in the actual kWh during any requested curtailment and the product of Customer's maximum load immediately preceding curtailment less Customer's designated curtailable load designated in the contract multiplied by the time period (hours) of a requested curtailment {Actual kWh – [(Max kVA preceding – Designated Curtailable kVA) x hours of requested T
curtailment]}. Non-compliance for each requested physical curtailment shall be the measured positive value determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) the Customer's maximum demand during such curtailment.

RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service	$ 2.25 per kVA of Curtailable Billing Demand	R/T
Primary Voltage Service	$ 2.30 per kVA of Curtailable Billing Demand	R/T
Non-Compliance Charge of:	$16.00 per kVA	T

Failure of Customer to curtail when requested to do so may result in termination of service under this rider. Customer will be charged for the portion of each requested curtailment not met at the applicable standard charges. The Company and Customer may arrange to have installed, at Customer's expense, the necessary telecommunication and control equipment to allow the Company to control Customers' curtailable load. Non-compliance charges will be waived if failure to curtail is a result of failure of Company's equipment; however, non-compliance charges will not be waived if failure to curtail is a result of Customer's equipment. If arrangements are made to have telecommunication and control equipment installed, then backup arrangements must also be established in the event either Company's or Customer's equipment fails.

CURTAILABLE BILLING DEMAND

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) the Customer's measured maximum kilowatt demand during the billing period for any billing T
interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M. (EST) and (ii) for the months October continuously through April, from 6 A.M. to 10 P.M, (EST) and (b) the firm contract demand.

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Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 51.2

Standard Rate Rider CSR30
Curtailable Service Rider 30

AUTOMATIC BUY-THROUGH PRICE

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP represents the mid-point price for natural gas ($/MMBtu) posted for the day in "Gas Daily" for Dominion—South Point and will be used for the electrical day from 12 midnight to midnight. Also the posted price for Monday or the day after a holiday is the posted price for Saturday, Sunday and the holiday.

TERM OF CONTRACT

The minimum original contract period shall be one (1) year and thereafter until terminated by giving at least six (6) months previous written notice, but Company may require that contract be executed for a longer initial term when deemed reasonably necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

When the Company requests curtailment, upon request by the Customer, the Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by the Company, the Customer shall provide to the Company a good-faith, non-binding short-term operational schedule for their facility. Upon request by the Customer, the Company will provide, once per month, to the Customer an explanation of the reasons for any request for curtailment.

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 51.2

Standard Rate Rider CSR30
Curtailable Service Rider 30

CURTAILABLE BILLING DEMAND (continued) T

For a Customer electing Option B, Curtailable Billing Demand shall be the customer Designated Curtailable Load, as described above. T T

AUTOMATIC BUY-THROUGH PRICE

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP represents the mid-point price for natural gas ($/MMBtu) posted for the day in *Platts Gas Daily* for Dominion—South Point and will be used for the electrical day from 12 midnight to midnight. Also the posted price for Monday or the day after a holiday is the posted price for Saturday, Sunday and the holiday. T

TERM OF CONTRACT

The minimum original contract period shall be one (1) year and thereafter until terminated by giving at least six (6) months previous written notice, but Company may require that contract be executed for a longer initial term when deemed reasonably necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

When the Company requests curtailment, upon request by the Customer, the Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by the Company, the Customer shall provide to the Company a good-faith, non-binding short-term operational schedule for their facility. Upon request by the Customer, the Company will provide, once per month, to the Customer an explanation of the reasons for any request for curtailment.

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 53

Standard Rate Rider	LRI
	Load Reduction Incentive Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule shall be made available as a rider to any customer served on Company's standard tariffs, having stand-by generation facilities of at least 500 kW, and agreeing to operate such facilities in accordance with the terms and conditions of this tariff. Service under this schedule is offered for a total maximum contracted load of 10,000 kW.

RATE

Up to $0.30 per kWh

TERMS AND CONDITIONS

1) Company will have the option to require Customer to operate Customer's stand-by generation to replace Customer's electric usage. Such period of generation shall not exceed 8 hours in any 24-hour period nor shall the total hours of generation in any 12-month period exceed 300 hours.
2) Should Company request Customer to operate Customer's stand-by generation, Company will notify Customer by 12 noon on a day ahead basis.
3) Company's request for Customer to operate Customer's stand-by generation will include an offer of a payment per kWh for Customer to operate Customer's stand-by generation.
4) Customer is obligated to operate Customer's stand-by generation should Customer accept Company's offered price.
5) Customer's stand-by generation shall not be operated in parallel with Company's system (i.e., such generation shall be connected to circuits which are isolated from Company's system).
6) Customer will be responsible for maintaining Customer's stand-by generation, including an adequate fuel supply, to ensure meeting Customer's obligation under this schedule.
7) Company will meter the output of Customer's stand-by generation, base the payment for Customer reducing load on the metered output, and provide payment to Customer through a credit to Customer's standard service billing.
8) Customer may provide Company with the option to install equipment that will permit Company to remotely start stand-by generation and switch circuits to such generation so that they are isolated from Company's system.
9) Company has no obligation to request operation of Customer's stand-by generation nor to provide any credit to Customer without first requesting Customer to provide stand-by generation.

TERM OF CONTRACT

The minimum term of contract shall be for one (1) year and thereafter until terminated by either party giving at least six (6) months written notice. Company may require a longer initial term when deemed necessary. Failure of Customer to operate stand-by generation may result in termination of contract.

Date of Issue: August 6, 2010
Date Effective: August 1, 2006
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

The current KU Load Reduction Incentive Rider LRI is proposed to be eliminated.

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 55

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE:
In all territory served.

AVAILABILITY OF SERVICE
This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy only from the owner of qualifying cogeneration or small power production facilities of 100 kW or less (such owner being hereafter called "Seller") installed on Seller's property to provide all or part of its requirements of electrical energy, or from which facilities Seller may elect to sell to Company all or part of such output of electrical energy.

Company will permit Seller's generating facilities to operate in parallel with Company's system under conditions set out below under "Parallel Operation".

Company will purchase such energy from Seller at the Rate, A or B, set out below and selected as hereafter provided, and under the terms and conditions stated herein. Company reserves the right to change the said Rates, upon proper filing with and acceptance by the jurisdictional Commission.

RATE A: TIME-DIFFERENTIATED RATE

1. For summer billing months of June, July, August and September, during the hours 9:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours),	$0.04538 per kWh
2. For winter billing months of December, January and February, during the hours 7:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours),	$0.04023 per kWh
3. During all other hours (off-peak hours)	$0.03139 per kWh

Determination of On-Peak and Off-Peak Hours: On-peak hours are defined as the hours of 9:01 A.M. through 10:00 P.M., E.D.T. (8:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 1 above), and the hours of 7:01 A.M. through 10:00 P.M., E.D.T. (6:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 2 above). Off-peak hours are defined as all hours other than those listed as on-peak (under 3 above). Company reserves the right to change the hours designated as on-peak from time to time as conditions indicate to be appropriate.

RATE B: NON-TIME-DIFFERENTIATED RATE

For all kWh purchased by Company, $0.03418 per kWh

Date of Issue: August 6, 2010
Date Effective: June 30, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 55

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE:
In all territory served.

AVAILABILITY OF SERVICE
This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy only from the owner of qualifying cogeneration or small power production facilities of 100 kW or less (such owner being hereafter called "Seller") installed on Seller's property to provide all or part of its requirements of electrical energy, or from which facilities Seller may elect to sell to Company all or part of such output of electrical energy.

Company will permit Seller's generating facilities to operate in parallel with Company's system under conditions set out below under "Parallel Operation".

Company will purchase such energy from Seller at the Rate, A or B, set out below and selected as hereafter provided, and under the terms and conditions stated herein. Company reserves the right to change the said Rates, upon proper filing with and acceptance by the jurisdictional Commission.

RATE A: TIME-DIFFERENTIATED RATE

1. For summer billing months of June, July, August and September, during the hours 9:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours),	$0.04538 per kWh
2. For winter billing months of December, January and February, during the hours 7:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours),	$0.04023 per kWh
3. During all other hours (off-peak hours)	$0.03139 per kWh

Determination of On-Peak and Off-Peak Hours: On-peak hours are defined as the hours of 9:01 A.M. through 10:00 P.M., E.D.T. (8:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 1 above), and the hours of 7:01 A.M. through 10:00 P.M., E.D.T. (6:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 2 above). Off-peak hours are defined as all hours other than those listed as on-peak (under 3 above). Company reserves the right to change the hours designated as on-peak from time to time as conditions indicate to be appropriate.

RATE B: NON-TIME-DIFFERENTIATED RATE

For all kWh purchased by Company, $0.03418 per kWh

Date of Issue: June 29, 2012
Date Effective: June 30, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 55.1

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

SELECTION OF RATE AND METERING

Subject to provisions hereafter in this Section relative to payment of costs of metering equipment, either Seller or Company may select Rate A, the Time-Differentiated Rate, for application to Company's said purchases of energy from Seller. If neither Seller nor Company selects Rate A, then Rate B, the Non-Time-Differentiated Rate, shall apply.

If neither Seller nor Company selects Rate A, and Rate B therefore is to apply to such purchases, Company, at Seller's cost, will install, own and operate a non-time-differentiated meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system. Such meter will be tested at intervals prescribed by Commission Regulation, with Seller having a right to witness all such tests; and Seller will pay to Company its fixed cost on such meter and equipment, expense of such periodic tests of the meter and any other expenses (all such costs and expenses, together, being hereafter called "costs of non-time-differentiated metering").

If either Seller or Company selects Rate A to apply to Company's said purchases of energy from Seller, the party (Seller or Company) so selecting Rate A shall pay (a) the cost of a time-differentiated recording meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system, required for the application of Rate A, in excess of (b) the costs of non-time-differentiated metering which shall continue to be paid by Seller.

In addition to metering referred to above, Company at its option and cost may install, own and operate, on Seller's generator, a recording meter to record the capacity, energy and reactive output of such generator at specified time intervals.

Company shall have access to all such meters at reasonable times during Seller's normal business hours, and shall regularly provide to Seller copies of all information provided by such meters.

PAYMENT

Any payment due from Company to Seller will be due within twelve (12) days from date of Company's reading of meter; provided, however, that, if Seller is a customer of Company, in lieu of such payment Company may offset its payment due to Seller hereunder, against Seller's next bill and payment due to Company for Company's service to Seller as customer.

PARALLEL OPERATION

Company hereby permits Seller to operate its generating facilities in parallel with Company's system, under the following conditions and any other conditions required by Company where unusual conditions not covered herein arise:

1. Prior to installation in Seller's system of any generator and associated facilities which are intended to be interconnected and operated in parallel with Company's system, or prior to the inter-connection to Company's system of any such generator and associated facilities already installed in Seller's system, Seller will provide to Company plans for such generator

Date of Issue: August 6, 2010
Date Effective: December 5, 1985
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 55.1

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

SELECTION OF RATE AND METERING

Subject to provisions hereafter in this Section relative to payment of costs of metering equipment, either Seller or Company may select Rate A, the Time-Differentiated Rate, for application to Company's said purchases of energy from Seller. If neither Seller nor Company selects Rate A, then Rate B, the Non-Time-Differentiated Rate, shall apply.

If neither Seller nor Company selects Rate A, and Rate B therefore is to apply to such purchases, Company, at Seller's cost, will install, own and operate a non-time-differentiated meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system. Such meter will be tested at intervals prescribed by Commission Regulation, with Seller having a right to witness all such tests; and Seller will pay to Company its fixed cost on such meter and equipment, expense of such periodic tests of the meter and any other expenses (all such costs and expenses, together, being hereafter called "costs of non-time-differentiated metering").

If either Seller or Company selects Rate A to apply to Company's said purchases of energy from Seller, the party (Seller or Company) so selecting Rate A shall pay (a) the cost of a time-differentiated recording meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system, required for the application of Rate A, in excess of (b) the costs of non-time-differentiated metering which shall continue to be paid by Seller.

In addition to metering referred to above, Company at its option and cost may install, own and operate, on Seller's generator, a recording meter to record the capacity, energy and reactive output of such generator at specified time intervals.

Company shall have access to all such meters at reasonable times during Seller's normal business hours, and shall regularly provide to Seller copies of all information provided by such meters.

PAYMENT

Any payment due from Company to Seller will be due within twelve (12) days from date of Company's reading of meter; provided, however, that, if Seller is a customer of Company, in lieu of such payment Company may offset its payment due to Seller hereunder, against Seller's next bill and payment due to Company for Company's service to Seller as customer.

PARALLEL OPERATION

Company hereby permits Seller to operate its generating facilities in parallel with Company's system, under the following conditions and any other conditions required by Company where unusual conditions not covered herein arise:

1. Prior to installation in Seller's system of any generator and associated facilities which are intended to be interconnected and operated in parallel with Company's system, or prior to the inter-connection to Company's system of any such generator and associated facilities already installed in Seller's system, Seller will provide to Company plans for such generator

Date of Issue: June 29, 2012
Date Effective: December 5, 1985
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

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and facilities. Company may, but shall have no obligation to, examine such plans and disapprove them in whole or in part, to the extent Company believes that such plans and proposed facilities will not adequately assure the safety of Company's facilities or system. Seller acknowledges and agrees that the sole purpose of any Company examination of such plans is the satisfaction of Company's interest in the safety of Company's own facilities and system, and that Company shall have no responsibility of any kind to Seller or to any other party in connection with any such examination. If Seller thereafter proposes any change from such plans submitted to Company, prior to the implementation thereof Seller will provide to Company new plans setting out such proposed change(s).

2. Seller will own, install, operate and maintain all generating facilities on its plant site, such facilities to include, but not be limited to, (a) protective equipment between the systems of Seller and Company and (b) necessary control equipment to synchronize frequency and voltage between such two systems. Seller's voltage at the point of interconnection will be the same as Company's system voltage. Suitable circuit breakers or similar equipment, as specified by Company, will be furnished by Seller at a location designated by Company to enable the separation or disconnection of the two electrical systems. Except in emergencies, the circuit breakers, or similar equipment, will be operated only by, or at the express direction of, Company personnel and will be accessible to Company at all times. In addition, a circuit breaker or similar equipment shall be furnished and installed by Seller to separate or disconnect Seller's generator.

3. Seller will be responsible for operating the generator and all facilities owned by Seller, except as hereafter specified. Seller will maintain its system in synchronization with Company's system.

4. Seller will (a) pay Company for all damage to Company's equipment, facilities or system, and (b) save and hold Company harmless from all claims, demands and liabilities of every kind and nature for injury or damage to, or death of, persons and/or property of others, including costs and expenses of defending against the same, arising in any manner in connection with Seller's generator, equipment, facilities or system or the operation thereof.

5. Seller will construct any additional facilities, in addition to generating and associated (interface) facilities, required for interconnection unless Company and Seller agree to Company's constructing such facilities, at Seller's expense, where Seller is not a customer of Company. When Seller is a customer of Company and Company is required to construct facilities different than otherwise required to permit interconnection, Seller shall pay such additional cost of facilities. Seller agrees to reimburse Company, at the time of installation, or, if agreed to by both parties, over a period of up to three (3) years, for any facilities including any hereafter required (but exclusive of metering equipment, elsewhere herein provided for) constructed by Company to permit Seller to operate interconnected with Company's system. When interconnection costs are repaid over a period of time, such payments will be made monthly and include interest on the unpaid balance at the percentage rate equal to the capital costs that Company would experience at such time by new financing, based on Company's then existing capital structure, with return on equity to be at the rate allowed in Company's immediately preceding rate case.

and facilities. Company may, but shall have no obligation to, examine such plans and disapprove them in whole or in part, to the extent Company believes that such plans and proposed facilities will not adequately assure the safety of Company's facilities or system. Seller acknowledges and agrees that the sole purpose of any Company examination of such plans is the satisfaction of Company's interest in the safety of Company's own facilities and system, and that Company shall have no responsibility of any kind to Seller or to any other party in connection with any such examination. If Seller thereafter proposes any change from such plans submitted to Company, prior to the implementation thereof Seller will provide to Company new plans setting out such proposed change(s).

2. Seller will own, install, operate and maintain all generating facilities on its plant site, such facilities to include, but not be limited to, (a) protective equipment between the systems of Seller and Company and (b) necessary control equipment to synchronize frequency and voltage between such two systems. Seller's voltage at the point of interconnection will be the same as Company's system voltage. Suitable circuit breakers or similar equipment, as specified by Company, will be furnished by Seller at a location designated by Company to enable the separation or disconnection of the two electrical systems. Except in emergencies, the circuit breakers, or similar equipment, will be operated only by, or at the express direction of, Company personnel and will be accessible to Company at all times. In addition, a circuit breaker or similar equipment shall be furnished and installed by Seller to separate or disconnect Seller's generator.

3. Seller will be responsible for operating the generator and all facilities owned by Seller, except as hereafter specified. Seller will maintain its system in synchronization with Company's system.

4. Seller will (a) pay Company for all damage to Company's equipment, facilities or system, and (b) save and hold Company harmless from all claims, demands and liabilities of every kind and nature for injury or damage to, or death of, persons and/or property of others, including costs and expenses of defending against the same, arising in any manner in connection with Seller's generator, equipment, facilities or system or the operation thereof.

5. Seller will construct any additional facilities, in addition to generating and associated (interface) facilities, required for interconnection unless Company and Seller agree to Company's constructing such facilities, at Seller's expense, where Seller is not a customer of Company. When Seller is a customer of Company and Company is required to construct facilities different than otherwise required to permit interconnection, Seller shall pay such additional cost of facilities. Seller agrees to reimburse Company, at the time of installation, or, if agreed to by both parties, over a period of up to three (3) years, for any facilities including any hereafter required (but exclusive of metering equipment, elsewhere herein provided for) constructed by Company to permit Seller to operate interconnected with Company's system. When interconnection costs are repaid over a period of time, such payments will be made monthly and include interest on the unpaid balance at the percentage rate equal to the capital costs that Company would experience at such time by new financing, based on Company's then existing capital structure, with return on equity to be at the rate allowed in Company's immediately preceding rate case.

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 55.3

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

6. Company will have the continuing right to inspect and approve Seller's facilities, described herein, and to request and witness any tests necessary to determine that such facilities are installed and operating properly; but Company will have no obligation to inspect or approve facilities, or to request or witness tests; and Company will not in any manner be responsible for Seller's facilities or any operation thereof.

7. Seller assumes all responsibility for the electric service upon Seller's premises at and from the point of any delivery or flow of electricity from Company, and for the wires and equipment used in connection therewith; and Seller will protect and save Company harmless from all claims for injury or damage to persons or property, including but not limited to property of Seller, occurring on or about Seller's premises or at and from the point of delivery or flow of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage is proved to have been caused solely by the negligence of Company.

8. Each, Seller and Company, will designate one or more Operating Representatives for the purpose of contacts and communications between the parties concerning operations of the two systems.

9. Seller will notify Company's Energy Control Center prior to each occasion of Seller's generator being brought into or (except in cases of emergencies) taken out of operation.

10. Company reserves the right to curtail a purchase from Seller when:

    (a) the purchase will result in costs to Company greater than would occur if the purchase were not made but instead Company, itself, generated an equivalent amount of energy; or

    (b) Company has a system emergency and purchases would (or could) contribute to such emergency.

    Seller will be notified of each curtailment.

TERMS AND CONDITIONS

Except as provided herein, conditions or operations will be as provided in Company's Terms and Conditions.

Date of Issue: August 6, 2010
Date Effective: December 5, 1985
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 55.3

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

6. Company will have the continuing right to inspect and approve Seller's facilities, described herein, and to request and witness any tests necessary to determine that such facilities are installed and operating properly; but Company will have no obligation to inspect or approve facilities, or to request or witness tests; and Company will not in any manner be responsible for Seller's facilities or any operation thereof.

7. Seller assumes all responsibility for the electric service upon Seller's premises at and from the point of any delivery or flow of electricity from Company, and for the wires and equipment used in connection therewith; and Seller will protect and save Company harmless from all claims for injury or damage to persons or property, including but not limited to property of Seller, occurring on or about Seller's premises or at and from the point of delivery or flow of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage is proved to have been caused solely by the negligence of Company.

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    (a) the purchase will result in costs to Company greater than would occur if the purchase were not made but instead Company, itself, generated an equivalent amount of energy; or

    (b) Company has a system emergency and purchases would (or could) contribute to such emergency.

    Seller will be notified of each curtailment.

TERMS AND CONDITIONS

Except as provided herein, conditions or operations will be as provided in Company's Terms and Conditions.

Date of Issue: June 29, 2012
Date Effective: December 5, 1985
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 56

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

AVAILABILITY

In all territory served.

APPLICABILITY OF SERVICE

Applicable to any small power production or cogeneration "qualifying facility" with capacity over 100 kW as defined by the Kentucky Public Service Commission Regulation 807 KAR 5:054, and which contracts to sell energy or capacity or both to Company.

RATES FOR PURCHASES FROM QUALIFYING FACILITIES

Energy Component Payments

The hourly avoided energy cost (AEC) in $ per MWh, which is payable to a QF for delivery of energy, shall be equal to Company's actual variable fuel expenses, for Company-owned coal and natural gas-fired production facilities, divided by the associated megawatt-hours of generation, as determined for the previous month. The total amount of the avoided energy cost payment to be made to a QF in an hour is equal to [AEC x E_{QF}], where E_{QF} is the amount of megawatt-hours delivered by a QF in that hour and which are determined by suitable metering.

Capacity Component Payments

The hourly avoided capacity cost (ACC) in $ per MWh, which is payable to a QF for delivery of capacity, shall be equal to the effective purchase price for power available to Company from the inter-utility market (which includes both energy and capacity charges) less Company's actual variable fuel expense (AEC). The total amount of the avoided capacity cost payment to be made to a QF in an hour is equal to [ACC x CAP_I], where CAP_I, the capacity delivered by the QF, is determined on the basis of the system demand (D_I) and Company's need for capacity in that hour to adequately serve the load.

Determination of CAP_I

For the following determination of CAP_I, C_{KU} represents Company's installed or previously arranged capacity at the time a QF signs a contract to deliver capacity; C_{QF} represents the actual capacity provided by a QF, but no more than the contracted capacity; and C_M represents capacity purchased from the inter-utility market.

1. System demand is less than or equal to Company's capacity:
   $D_I \leq C_{KU}$; $CAP_I = 0$
2. System demand is greater than Company's capacity but less than or equal to the total of Company's capacity and the capacity provided by a QF:

   $C_{KU} < D_I \leq [C_{KU} + C_{QF}]$; $CAP_I = C_M$

Date of Issue: August 6, 2010
Date Effective: April 17, 1999
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 56

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

AVAILABILITY

In all territory served.

APPLICABILITY OF SERVICE

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   $C_{KU} < D_I \leq [C_{KU} + C_{QF}]$; $CAP_I = C_M$

Date of Issue: June 29, 2012
Date Effective: April 17, 1999
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

3. System demand is greater than the total of Company's capacity and the capacity provided by a QF:

   $D_I > [C_{KU} + C_{QF}]$; $CAP_I = C_{QF}$

PAYMENT

Company shall pay each bill for electric power rendered to it in accordance with the terms of the contract, within twelve (12) days of the date the bill is rendered. In lieu of such payment plan, Company will, upon written request, credit the Customer's account for such purchases.

TERM OF CONTRACT

For contracts which cover the purchase of energy only, the term shall be one (1) year, and shall be self-renewing from year-to-year thereafter, unless canceled by either party on one (1) year's written notice.

For contracts which cover the purchase of capacity and energy, the term shall be five (5) years.

TERMS AND CONDITIONS

1. Qualifying facilities shall be required to pay for any additional interconnection costs, to the extent that such costs are in excess of those that Company would have incurred if the qualifying facility's output had not been purchased.
2. A qualifying facility operating in parallel with Company must demonstrate that its equipment is designed, installed, and operated in a manner that insures safe and reliable interconnected operation. A qualifying facility should contact Company for assistance in this regard.
3. The purchasing, supplying and billing for service, and all conditions applying hereto, shall be specified in the contract executed by the parties, and are subject to the jurisdiction of the Kentucky Public Service Commission, and to Company's Terms and Conditions currently in effect, as filed with the Commission.

3. System demand is greater than the total of Company's capacity and the capacity provided by a QF:

   $D_I > [C_{KU} + C_{QF}]$; $CAP_I = C_{QF}$

PAYMENT

Company shall pay each bill for electric power rendered to it in accordance with the terms of the contract, within twelve (12) days of the date the bill is rendered. In lieu of such payment plan, Company will, upon written request, credit the Customer's account for such purchases.

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Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 57

Standard Rate Rider NMS
Net Metering Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to any customer-generator who owns and operates a generating facility located on Customer's premises that generates electricity using solar, wind, biomass or biogas, or hydro energy in parallel with Company's electric distribution system to provide all or part of Customer's electrical requirements, and who executes Company's written Application for Interconnection and Net Metering. The generation facility shall be limited to a maximum rated capacity of 30 kilowatts. This Standard Rate Rider is intended to comply with all provisions of the Interconnection and Net Metering Guidelines approved by the Public Service Commission of Kentucky, which can be found on-line at www.psc.ky.gov as Appendix A to the January 8, 2009 Order in Administrative Case No. 2008-00169.

METERING AND BILLING
Net metering service shall be measured using a single meter or, as determined by Company, additional meters and shall be measured in accordance with standard metering practices by metering equipment capable of registering power flow in both directions for each time period defined by the applicable rate schedule. This net metering equipment shall be provided without any cost to the Customer. This provision does not relieve Customer's responsibility to pay metering costs embedded in the Company's Commission-approved base rates. Additional meters, requested by Customer, will be provided at Customer's expense.

If electricity generated by Customer and fed back to Company's system exceeds the electricity supplied to Customer from the system during a billing period, Customer shall receive a credit for the net delivery on Customer's bill for the succeeding billing periods. Any such unused excess credits will be carried forward and drawn on by Customer as needed. Unused excess credits existing at the time Customer's service is terminated end with Customer's account and are not transferrable between customers or locations.

NET METERING SERVICE INTERCONNECTION GUIDELINES
General – Customer shall operate the generating facility in parallel with Company's system under the following conditions and any other conditions required by Company where unusual circumstances arise not covered herein:

1. Customer to own, operate, and maintain all generating facilities on their premises. Such facilities shall include, but not be limited to, necessary control equipment to synchronize frequency, voltage, etc., between Customer's and Company's system as well as adequate protective equipment between the two systems. Customer's voltage at the point of interconnection will be the same as Company's system voltage.
2. Customer will be responsible for operating all generating facilities owned by Customer, except as specified hereinafter. Customer will maintain its system in synchronization with Company's system.
3. Customer will be responsible for any damage done to Company's equipment due to failure of Customer's control, safety, or other equipment.
4. Customer agrees to inform Company of any changes it wishes to make to its generating or associated facilities that differ from those initially installed and described to Company in writing and obtain prior approval from Company.
5. Company will have the right to inspect and approve Customer's facilities described herein, and to conduct any tests necessary to determine that such facilities are installed and

Date of Issue: August 6, 2010
Date Effective: August 17, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 57

Standard Rate Rider NMS
Net Metering Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to any customer-generator who owns and operates a generating facility located on Customer's premises that generates electricity using solar, wind, biomass or biogas, or hydro energy in parallel with Company's electric distribution system to provide all or part of Customer's electrical requirements, and who executes Company's written Application for Interconnection and Net Metering. The generation facility shall be limited to a maximum rated capacity of 30 kilowatts. This Standard Rate Rider is intended to comply with all provisions of the Interconnection and Net Metering Guidelines approved by the Public Service Commission of Kentucky, which can be found on-line at www.psc.ky.gov as Appendix A to the January 8, 2009 Order in Administrative Case No. 2008-00169.

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2. Customer will be responsible for operating all generating facilities owned by Customer, except as specified hereinafter. Customer will maintain its system in synchronization with Company's system.
3. Customer will be responsible for any damage done to Company's equipment due to failure of Customer's control, safety, or other equipment.
4. Customer agrees to inform Company of any changes it wishes to make to its generating or associated facilities that differ from those initially installed and described to Company in writing and obtain prior approval from Company.
5. Company will have the right to inspect and approve Customer's facilities described herein, and to conduct any tests necessary to determine that such facilities are installed and

Date of Issue: June 29, 2012
Date Effective: August 17, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

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NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

operating properly; however, Company will have no obligation to inspect, witness tests, or in any manner be responsible for Customer's facilities or operation thereof.

6. Customer assumes all responsibility for the electric service on Customer's premises at and from the point of delivery of electricity from Company and for the wires and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence or willful misconduct of Company.

Level 1 – A Level 1 installation is defined as an inverter-based generator certified as meeting the requirements of Underwriters Laboratories Standard 1741 and meeting the following conditions:

1. The aggregated net metering generation on a radial distribution circuit will not exceed 15% of the line section's most recent one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
2. The aggregated net metering generation on a shared singled-phase secondary will not exceed 20 kVA or the nameplate rating of the service transformer.
3. A single-phase net metering generator interconnected on the center tap neutral of a 240 volt service shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.
4. A net metering generator interconnected to Company's three-phase, three-wire primary distribution lines, shall appear as a phase-to-phase connection to Company's primary distribution line.
5. A net metering generator interconnected to Company's three-phase, four-wire primary distribution lines, shall appear as an effectively grounded source to Company's primary distribution line.
6. A net metering generator will not be connected to an area or spot network.
7. There are no identified violations of the applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems".
8. Company will not be required to construct any facilities on its own system to accommodate the net metering generator.

Customer desiring a Level 1 interconnection shall submit a "LEVEL 1 - Application for Interconnection and Net Metering." Company shall notify Customer within 20 business days as to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, the Company will notify Customer, and the time between notification and submission of the information shall not be counted towards the 20 business days. Approval is contingent upon an initial inspection and witness test at the discretion of Company.

Level 2 – A Level 2 installation is defined as generator that is not inverter-based; that uses equipment not certified as meeting the requirements of Underwriters Laboratories Standard 1741, or that does not meet one or more of the conditions required of a Level 1 net metering generator. A Level 2 Application will be approved if the generating facility meets the Company's technical interconnection requirements. Those requirements are available on line at www.lge-ku.com and upon request.

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

operating properly; however, Company will have no obligation to inspect, witness tests, or in any manner be responsible for Customer's facilities or operation thereof.

6. Customer assumes all responsibility for the electric service on Customer's premises at and from the point of delivery of electricity from Company and for the wires and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence or willful misconduct of Company.

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Standard Rate Rider — NMS
Net Metering Service

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

Customer desiring a Level 2 interconnection shall submit a "LEVEL 2 - Application for Interconnection and Net Metering." Company shall notify Customer within 30 business days as to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, the Company will notify Customer, and the time between notification and submission of the information shall not be counted towards the 30 business days. Approval is contingent upon an initial inspection and witness test at the discretion of Company.

Customer submitting a "Level 2 - Application for Interconnection and Net Metering" will provide a non-refundable inspection and processing fee of $100, and in the event that the Company determines an impact study to be necessary, shall be responsible for any reasonable costs of up to $1,000 of documented costs for the initial impact study.

Additional studies requested by Customer shall be at Customer's expense.

CONDITIONS OF INTERCONNECTION

Customer may operate his net metering generator in parallel with Company's system when complying with the following conditions:

1. Customer shall install, operate, and maintain, at Customer's sole cost and expense, any control, protective, or other equipment on Customer's system required by Company's technical interconnection requirements based on IEEE 1547, NEC, accredited testing laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the net metering generating facility in parallel with Company's system. Customer bears full responsibility for the installation, maintenance and safe operation of the net metering generating facility. Upon reasonable request from Company, Customer shall demonstrate compliance.
2. Customer shall represent and warrant compliance of the net metering generator with:
   a) any applicable safety and power standards established by IEEE and accredited testing laboratories;
   b) NEC, as may be revised from time-to-time;
   c) Company's rules and regulations and Terms and Conditions, as may be revised by time-to-time by the Public Service Commission of Kentucky;
   d) the rules and regulations of the Public Service Commission of Kentucky, as may be revised by time-to-time by the Public Service Commission of Kentucky:
   e) all other local, state, and federal codes and laws, as may be in effect from time-to-time.
3. Any changes or additions to Company's system required to accommodate the net metering generator shall be Customer's financial responsibility and Company shall be reimbursed for such changes or additions prior to construction.
4. Customer shall operate the net metering generator in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. Customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system.
5. Customer shall be responsible for protecting, at Customer's sole cost and expense, the net metering generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the net metering

Standard Rate Rider — NMS
Net Metering Service

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

Customer desiring a Level 2 interconnection shall submit a "LEVEL 2 - Application for Interconnection and Net Metering." Company shall notify Customer within 30 business days as to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, the Company will notify Customer, and the time between notification and submission of the information shall not be counted towards the 30 business days. Approval is contingent upon an initial inspection and witness test at the discretion of Company.

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CONDITIONS OF INTERCONNECTION

Customer may operate his net metering generator in parallel with Company's system when complying with the following conditions:

1. Customer shall install, operate, and maintain, at Customer's sole cost and expense, any control, protective, or other equipment on Customer's system required by Company's technical interconnection requirements based on IEEE 1547, NEC, accredited testing laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the net metering generating facility in parallel with Company's system. Customer bears full responsibility for the installation, maintenance and safe operation of the net metering generating facility. Upon reasonable request from Company, Customer shall demonstrate compliance.
2. Customer shall represent and warrant compliance of the net metering generator with:
   a) any applicable safety and power standards established by IEEE and accredited testing laboratories;
   b) NEC, as may be revised from time-to-time;
   c) Company's rules and regulations and Terms and Conditions, as may be revised by time-to-time by the Public Service Commission of Kentucky;
   d) the rules and regulations of the Public Service Commission of Kentucky, as may be revised by time-to-time by the Public Service Commission of Kentucky:
   e) all other local, state, and federal codes and laws, as may be in effect from time-to-time.
3. Any changes or additions to Company's system required to accommodate the net metering generator shall be Customer's financial responsibility and Company shall be reimbursed for such changes or additions prior to construction.
4. Customer shall operate the net metering generator in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. Customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system.
5. Customer shall be responsible for protecting, at Customer's sole cost and expense, the net metering generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the net metering

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 57.3

Standard Rate Rider NMS
Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

generator resulting solely from the negligence or willful misconduct on the part of the Company.

6. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to Customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the net metering generator comply with the requirements of this rate schedule.
7. Where required by the Company, Customer shall furnish and install on Customer's side of the point of interconnection a safety disconnect switch which shall be capable of fully disconnecting Customer's net metering generator from Company's electric service under the full rated conditions of Customer's net metering generator. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, Customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the net metering generator is operational. The disconnect switch shall be accessible to Company personnel at all times. Company may waive the requirement for an external disconnect switch for a net metering generator at its sole discretion, and on a case by case basis.
8. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the Customer to discontinue operation of the net metering generator if Company believes that:
   a) continued interconnection and parallel operation of the net metering generator with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or Customer's electric system;
   b) the net metering generator is not in compliance with the requirements of this rate schedule, and the non-compliance adversely affects the safety, reliability or power quality of Company's electric system; or
   c) the net metering generator interferes with the operation of Company's electric system.

   In non-emergency situations, Company shall give Customer notice of noncompliance including a description of the specific noncompliance condition and allow Customer a reasonable time to cure the noncompliance prior to isolating the Generating Facilities. In emergency situations, where the Company is unable to immediately isolate or cause Customer to isolate only the net metering generator, Company may isolate Customer's entire facility.
9. Customer agrees that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in net metering generator capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in net metering generator capacity is allowed without approval.
10. Customer shall protect, indemnify and hold harmless Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by Customer or Customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating

Date of Issue: August 6, 2010
Date Effective: April 17, 1999
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 57.3

Standard Rate Rider NMS
Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

generator resulting solely from the negligence or willful misconduct on the part of the Company.

6. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to Customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the net metering generator comply with the requirements of this rate schedule.
7. Where required by the Company, Customer shall furnish and install on Customer's side of the point of interconnection a safety disconnect switch which shall be capable of fully disconnecting Customer's net metering generator from Company's electric service under the full rated conditions of Customer's net metering generator. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, Customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the net metering generator is operational. The disconnect switch shall be accessible to Company personnel at all times. Company may waive the requirement for an external disconnect switch for a net metering generator at its sole discretion, and on a case by case basis.
8. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the Customer to discontinue operation of the net metering generator if Company believes that:
   a) continued interconnection and parallel operation of the net metering generator with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or Customer's electric system;
   b) the net metering generator is not in compliance with the requirements of this rate schedule, and the non-compliance adversely affects the safety, reliability or power quality of Company's electric system; or
   c) the net metering generator interferes with the operation of Company's electric system.

   In non-emergency situations, Company shall give Customer notice of noncompliance including a description of the specific noncompliance condition and allow Customer a reasonable time to cure the noncompliance prior to isolating the Generating Facilities. In emergency situations, where the Company is unable to immediately isolate or cause Customer to isolate only the net metering generator, Company may isolate Customer's entire facility.
9. Customer agrees that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in net metering generator capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in net metering generator capacity is allowed without approval.
10. Customer shall protect, indemnify and hold harmless Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by Customer or Customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating

Date of Issue: June 29, 2012
Date Effective: April 17, 1999
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Standard Rate Rider NMS

Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

Customer's net metering generator or any related equipment or any facilities owned by Company except where such injury, death or damage was caused or contributed to by the fault or negligence of Company or its employees, agents, representatives or contractors.

The liability of Company to Customer for injury to person and property shall be governed by the tariff(s) for the class of service under which Customer is taking service.

11. Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial or other policy) for generating facilities. Customer shall upon request provide Company with proof of such insurance at the time that application is made for net metering.

12. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

13. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify Customer in writing and list what must be done to place the facility in compliance.

14. Customer shall retain any and all Renewable Energy Credits (RECs) generated by Customer's generating facilities.

DEFINITIONS

"Billing period" shall be the time period between the dates on which Company issues the customer's bills.

"Billing Period Credit" shall be the electricity generated by the customer that flows into the electric system and which exceeds the electricity supplied to the customer from the electric system during any billing period.

TERMS AND CONDITIONS

Except as provided herein, service will be furnished under Company's Terms and Conditions applicable hereto.

Standard Rate Rider NMS

Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

Customer's net metering generator or any related equipment or any facilities owned by Company except where such injury, death or damage was caused or contributed to by the fault or negligence of Company or its employees, agents, representatives or contractors.

The liability of Company to Customer for injury to person and property shall be governed by the tariff(s) for the class of service under which Customer is taking service.

11. Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial or other policy) for generating facilities. Customer shall upon request provide Company with proof of such insurance at the time that application is made for net metering.
12. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.
13. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify Customer in writing and list what must be done to place the facility in compliance.
14. Customer shall retain any and all Renewable Energy Credits (RECs) generated by Customer's generating facilities.

DEFINITIONS

"Billing period" shall be the time period between the dates on which Company issues the customer's bills.

"Billing Period Credit" shall be the electricity generated by the customer that flows into the electric system and which exceeds the electricity supplied to the customer from the electric system during any billing period.

TERMS AND CONDITIONS

Except as provided herein, service will be furnished under Company's Terms and Conditions applicable hereto.

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 57.5
Canceling P.S.C. No. 15, Original Sheet No. 57.5

Standard Rate Rider — **NMS**
Net Metering Service

LEVEL 1

Application for Interconnection and Net Metering
Use this application form only for a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Submit this Application to:

Kentucky Utilities Company, Attn: Customer Commitment, P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact KU at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ______________________ Account Number: ____________

Customer Address: ______________________________________

Customer Phone No.: ____________ Customer E-mail Address: ________________

Project Contact Person: ______________________________________

Phone No.: ______________ E-mail Address (Optional): ________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

____

____

Energy Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Inverter Manufacturer and Model #: ______________________________

Inverter Power Rating: ______________ Inverter Voltage Rating: ______________

Power Rating of Energy Source (i.e., solar panels, wind turbine): ______________

Is Battery Storage Used: ____No ____Yes If Yes, Battery Power Rating: ______________

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing location of Utility's meter, energy source, ***(optional: Utility accessible disconnect switch)*** and inverter.

Attach single line drawing showing all electrical equipment from the Utility's metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ______________________

Date of Issue: February 2, 2012
Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case Nos. 2009-00548 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 57.5

Standard Rate Rider — **NMS**
Net Metering Service

LEVEL 1

Application for Interconnection and Net Metering
Use this application form only for a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Submit this Application to:

Kentucky Utilities Company, Attn: Customer Commitment, P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact KU at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ______________________ Account Number: ____________

Customer Address: ______________________________________

Customer Phone No.: ____________ Customer E-mail Address: ________________

Project Contact Person: ______________________________________

Phone No.: ______________ E-mail Address (Optional): ________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

Energy Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Inverter Manufacturer and Model #: ______________________________

Inverter Power Rating: ______________ Inverter Voltage Rating: ______________

Power Rating of Energy Source (i.e., solar panels, wind turbine): ______________

Is Battery Storage Used: ____No ____Yes If Yes, Battery Power Rating: ______________

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing location of Utility's meter, energy source, ***(optional: Utility accessible disconnect switch)*** and inverter.

Attach single line drawing showing all electrical equipment from the Utility's metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ______________________

Date of Issue: June 29, 2012
Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case Nos. 2009-00548 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 57.6
Canceling P.S.C. No. 15, Original Sheet No. 57.6

Standard Rate Rider NMS
Net Metering Service

LEVEL 2

Application for Interconnection and Net Metering
Use this application form when a generating facility is not inverter-based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or does not meet any of the additional conditions under Level 1.

Submit this Application, along with an application fee of $100, to:

Kentucky Utilities Company, Attn: Customer Commitment, P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact KU at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ______________________ Account Number: ____________

Customer Address: ______________________________

Project Contact Person: ______________________________

Phone No.: ______________ E-mail Address (Optional): ______________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

____

____

Total Generating Capacity of Generating Facility: ______________________________

Type of Generator: ____Inverter-Based ____Synchronous ____Induction

Power Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Adequate documentation and information must be submitted with this application to be considered complete. Typically this should include the following:

1. Single-line diagram of the customer's system showing all electrical equipment from the generator to the point of interconnection with the Utility's distribution system, including generators, transformers, switchgear, switches, breakers, fuses, voltage transformers, current transformers, wire sizes, equipment ratings, and transformer connections.
2. Control drawings for relays and breakers.
3. Site Plans showing the physical location of major equipment.
4. Relevant ratings of equipment. Transformer information should include capacity ratings, voltage ratings, winding arrangements, and impedance.
5. If protective relays are used, settings applicable to the interconnection protection. If programmable relays are used, a description of how the relay is programmed to operate as applicable to interconnection protection.
6. A description of how the generator system will be operated including all modes of operation.
7. For inverters, the manufacturer name, model number, and AC power rating. For certified inverters, attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.
8. For synchronous generators, manufacturer and model number, nameplate ratings, and impedance data (Xd, Xd, & Xd).
9. For induction generators, manufacturer and model number, nameplate ratings, and locked rotor current.

Customer Signature: ______________________ Date: ____________

Date of Issue: February 2, 2012
Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case Nos. 2009-00548 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 57.6

Standard Rate Rider NMS
Net Metering Service

LEVEL 2

Application for Interconnection and Net Metering
Use this application form when a generating facility is not inverter-based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or does not meet any of the additional conditions under Level 1.

Submit this Application, along with an application fee of $100, to:

Kentucky Utilities Company, Attn: Customer Commitment, P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact KU at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ______________________ Account Number: ____________

Customer Address: ______________________________

Project Contact Person: ______________________________

Phone No.: ______________ E-mail Address (Optional): ______________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

____

____

Total Generating Capacity of Generating Facility: ______________________________

Type of Generator: ____Inverter-Based ____Synchronous ____Induction

Power Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Adequate documentation and information must be submitted with this application to be considered complete. Typically this should include the following:

1. Single-line diagram of the customer's system showing all electrical equipment from the generator to the point of interconnection with the Utility's distribution system, including generators, transformers, switchgear, switches, breakers, fuses, voltage transformers, current transformers, wire sizes, equipment ratings, and transformer connections.
2. Control drawings for relays and breakers.
3. Site Plans showing the physical location of major equipment.
4. Relevant ratings of equipment. Transformer information should include capacity ratings, voltage ratings, winding arrangements, and impedance.
5. If protective relays are used, settings applicable to the interconnection protection. If programmable relays are used, a description of how the relay is programmed to operate as applicable to interconnection protection.
6. A description of how the generator system will be operated including all modes of operation.
7. For inverters, the manufacturer name, model number, and AC power rating. For certified inverters, attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.
8. For synchronous generators, manufacturer and model number, nameplate ratings, and impedance data (Xd, Xd, & Xd).
9. For induction generators, manufacturer and model number, nameplate ratings, and locked rotor current.

Customer Signature: ______________________ Date: ____________

Date of Issue: June 29, 2012
Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case Nos. 2009-00548 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 60

Standard Rate Rider EF
Excess Facilities

APPLICABILITY
In all territory served.

AVAILABILITY OF SERVICE
This rider is available for nonstandard service facilities which are considered to be in excess of the standard facilities that would normally be provided by Company. This rider does not apply to line extensions or to other facilities which are necessary to provide basic electric service. Company reserves the right to decline to provide service hereunder for any project (a) that exceeds $100,000 or (b) where Company does not have sufficient expertise to install, operate, or maintain the facilities or (c) where the facilities do not meet Company's safety requirements, or (d) where the facilities are likely to become obsolete prior to the end of the initial contract term.

DEFINITION OF EXCESS FACILITIES
Excess facilities are lines and equipment which are installed in addition to or in substitution for the normal facilities required to render basic electric service. Applications of excess facilities include, but are not limited to, emergency backup feeds, automatic transfer switches, redundant transformer capacity, and duplicate or check meters.

EXCESS FACILITIES CHARGE
Company shall provide normal operation and maintenance of the excess facilities. Should the facilities suffer failure, Company will provide for replacement of such facilities and the monthly charge will be adjusted to reflect the installed cost of the replacement facilities.

Customer shall pay for excess facilities by either (i) making a monthly excess facilities charge payment covering the cost of the leased facilities or (ii) making a one-time contribution-in-aid-of-construction (CIAC) payment and a monthly excess facilities charge associated with the operating expenses and expected replacement costs of the facilities.

For leased facilities, the customer shall pay a monthly Excess Facilities charge equal to the following percentage applied to the original installed cost of the facilities provided by the Company:

(i) Monthly Charge for Leased Facilities 1.54%

For facilities supported by a CIAC Payment, the customer shall pay a monthly Excess Facilities charge equal to the following percentage applied to the original installed cost of the facilities provided by the Company:

(ii) Monthly Charge for Facilities Supported by a one-time CIAC payment 0.74%

PAYMENT
The Excess Facilities Charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

TERM OF CONTRACT
The initial term of contract to the customer under this schedule shall be not less than five (5) years. The term shall continue automatically until terminated by either party upon at least one (1) month's written notice.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 60

Standard Rate Rider EF
Excess Facilities

APPLICABILITY
In all territory served.

AVAILABILITY OF SERVICE
This rider is available for nonstandard service facilities which are considered to be in excess of the standard facilities that would normally be provided by Company. This rider does not apply to line extensions or to other facilities which are necessary to provide basic electric service. Company reserves the right to decline to provide service hereunder for any project (a) that exceeds $100,000 or (b) where Company does not have sufficient expertise to install, operate, or maintain the facilities or (c) where the facilities do not meet Company's safety requirements, or (d) where the facilities are likely to become obsolete prior to the end of the initial contract term.

DEFINITION OF EXCESS FACILITIES
Excess facilities are lines and equipment which are installed in addition to or in substitution for the normal facilities required to render basic electric service and where such facilities are T
dedicated to a specific customer. Applications of excess facilities include, but are not limited to, T
emergency backup feeds, automatic transfer switches, redundant transformer capacity, and duplicate or check meters.

EXCESS FACILITIES CHARGE
Company shall provide normal operation and maintenance of the excess facilities. Should the facilities suffer failure, Company will provide for replacement of such facilities and the monthly charge will be adjusted to reflect the installed cost of the replacement facilities. No adjustment T
in the monthly charge for a replacement of facilities will be made during the initial five (5) year T
term of contract. T

Customer shall pay for excess facilities by: T

(a) making a monthly Excess Facilities Charge payment equal to the installed cost of the T
excess facilities times the following percentage: T

Percentage With No Contribution–in-Aid-of-Construction 1.28% T/R

(b) making a one-time Contribution-in-Aid-of-Construction equal to the installed cost of the T
excess facilities plus a monthly Excess Facilities Charge payment equal to the installed T
cost of the excess facilities times the following percentage: T

Percentage With Contribution-in-Aid of-Construction 0.49% T/R

PAYMENT
The Excess Facilities Charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

TERM OF CONTRACT
The initial term of contract to the customer under this schedule shall be not less than five (5) years. The term shall continue automatically until terminated by either party upon at least one (1) month's written notice.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 61

Standard Rate Rider — RC

Redundant Capacity

APPLICABLE

This rate is applicable to customers served under Company's rate schedules which include a demand charge or a special contract including a demand charge.

AVAILABILITY

Available to customers requesting the reservation of capacity on Company's facilities which are shared by other customers when Company has and is willing to reserve such capacity. Such facilities represent a redundant delivery to provide electric service to the Customer's facility in the event that an emergency or unusual occurrence renders the Customer's principal delivery unavailable for providing service.

RATE:

Capacity Reservation Charge

Secondary Distribution	$0.85 per kW per month
Primary Distribution	$0.68 per kW per month

Applicable to the greater of:

(1) the highest average load in kilowatts recorded at either the principal distribution feed metering point or at the redundant distribution feed metering point during any 15-minute interval in the monthly billing period;

(2) 50% of the maximum demand similarly determined for any of the eleven (11) preceding months; or

(3) the contracted capacity reservation.

TERM OF CONTRACT

The minimum contract term shall be five (5) years and shall be renewed for one-year periods until either party provides the other with ninety (90) days written notice of a desire to terminate the arrangement. Company may require that a contract be executed for a longer initial term when deemed necessary by the difficulty and/or high cost associated with providing the redundant feed or other special conditions.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 61

Standard Rate Rider — RC

Redundant Capacity

APPLICABLE

This rate is applicable to customers served under Company's rate schedules which include a demand charge or a special contract including a demand charge.

AVAILABILITY

Available to customers requesting the reservation of capacity on Company's facilities which are shared by other customers when Company has and is willing to reserve such capacity. Such facilities represent a redundant delivery to provide electric service to the Customer's facility in the event that an emergency or unusual occurrence renders the Customer's principal delivery unavailable for providing service. Where Customer desires to split a load between multiple meters on multiple feeds and contract for Redundant Capacity on those feeds, service is contingent on the practicality of metering to measure any transferred load to the redundant feed. T T T T

RATE:

Capacity Reservation Charge

Secondary Distribution	$1.55 per kW/kVA per month	I/T
Primary Distribution	$0.99 per kW/kVA per month	I/T

Applicable to the greater of:

(1) the highest average load in kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) recorded at either the principal distribution feed metering point or at the redundant distribution feed metering point during any 15-minute interval in the monthly billing period; T T

(2) 50% of the maximum demand similarly determined for any of the eleven (11) preceding months; or

(3) the contracted capacity reservation.

TERM OF CONTRACT

The minimum contract term shall be five (5) years and shall be renewed for one-year periods until either party provides the other with ninety (90) days written notice of a desire to terminate the arrangement. Company may require that a contract be executed for a longer initial term when deemed necessary by the difficulty and/or high cost associated with providing the redundant feed or other special conditions.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 62

Standard Rate Rider — SS

Supplemental or Standby Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This service is available as a rider to customers whose premises or equipment are regularly supplied with electric energy from generating facilities other than those of Company and who desire to contract with Company for reserve, breakdown, supplemental or standby service.

RATE

	Secondary	Primary	Transmission
Contract Demand per kVA per Month	$ 6.54	$ 6.17	$ 5.99

CONTRACT DEMAND

Contract Demand is defined as the number of kilowatts mutually agreed upon as representing customer's maximum service requirements and contracted for by customer; provided, however, if such number of kilowatts is exceeded by a recorded demand, such recorded demand shall become the new contract demand commencing with the month in which recorded and continuing for the remaining term of the contract or until superseded by a higher recorded demand.

MINIMUM CHARGE

Electric service actually used each month will be charged for in accordance with the provisions of the applicable rate schedule; provided, however, the minimum billing under that rate schedule shall in no case be less than an amount calculated at the appropriate rate above applied to the Contract Demand.

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

SPECIAL TERMS AND CONDITIONS

1) In order to protect its equipment from overload damage, Company may require customer to install at Customer's own expense an approved shunt trip type breaker and an approved automatic pole-mounted disconnect. Such circuit breakers shall be under the sole control of Company and will be set by Company to break the connection with its service in the event customer's demand materially exceeds that for which the customer contracted.

2) In the event customer's use of service is intermittent or subject to violent fluctuations, Company will require customer to install and maintain at Customer's own expense suitable equipment to satisfactorily limit such intermittence or fluctuations.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 62

Standard Rate Rider — SS

Supplemental or Standby Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This service is available as a rider to customers whose premises or equipment are regularly supplied with electric energy from generating facilities other than those of Company and who desire to contract with Company for reserve, breakdown, supplemental or standby service.

Where a customer-generator supplies all or part of the customer-generator's own load and desires Company to provide supplemental or standby service for that load, the customer-generator must contract for such service under Company's Supplemental or Standby Service Rider, otherwise Company has no obligation to supply the non-firm service. This requirement does not apply to Net Metering Service (Rider NMS). T

RATE

	Secondary	Primary	Transmission	
Contract Demand per kW/kVA per Month	$12.91	$12.35	$11.17	T/I

CONTRACT DEMAND

Contract Demand is defined as the number of kW/kVA (as is appropriate for the demand basis T
of the standard rate on which Customer is billed) mutually agreed upon as representing T
customer's maximum service requirements and contracted for by customer; provided, however,
if such number of kW/kVA (as is appropriate for the demand basis of the standard rate on which T
Customer is billed) is exceeded by a recorded demand, such recorded demand shall become T
the new contract demand commencing with the month in which recorded and continuing for the remaining term of the contract or until superseded by a higher recorded demand.

MINIMUM CHARGE

Electric service actually used each month will be charged for in accordance with the provisions of the applicable rate schedule; provided, however, the minimum billing under that rate schedule shall in no case be less than an amount calculated at the appropriate rate above applied to the Contract Demand.

DUE DATE OF BILL

Customer's payment will be due within twelve (12) calendar days from the date of the bill.

SPECIAL TERMS AND CONDITIONS

1) In order to protect its equipment from overload damage, Company may require customer to install at Customer's own expense an approved shunt trip type breaker and an approved automatic pole-mounted disconnect. Such circuit breakers shall be under the sole control of Company and will be set by Company to break the connection with its service in the event customer's demand materially exceeds that for which the customer contracted.

T

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 62.1

Standard Rate Rider SS

Supplemental or Standby Service

SPECIAL TERMS AND CONDITIONS (continued)

3) Customer's generating equipment shall not be operated in parallel with Company's service until the manner of such operation has been approved by Company and is in compliance with Company's operating standards for system reliability and safety.

TERM OF CONTRACT

The minimum contract period shall be one (1) year, but Company may require that a contract be executed for a longer initial term when deemed necessary by the size of load or special conditions.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions except as provided herein.

Date of Issue: August 6, 2010
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 62.1

Standard Rate Rider SS

Supplemental or Standby Service

SPECIAL TERMS AND CONDITIONS (continued)

2) In the event customer's use of service is intermittent or subject to violent fluctuations, Company will require customer to install and maintain at Customer's own expense suitable equipment to satisfactorily limit such intermittence or fluctuations. T T T

3) Customer's generating equipment shall not be operated in parallel with Company's service until the manner of such operation has been approved by Company and is in compliance with Company's operating standards for system reliability and safety.

TERM OF CONTRACT

The minimum contract period shall be one (1) year, but Company may require that a contract be executed for a longer initial term when deemed necessary by the size of load or special conditions.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions except as provided herein.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 65

Standard Rate Rider IL

Rider for Intermittent Loads

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule applies to all loads having a detrimental effect upon the electric service rendered to other customers of Company or upon Company's facilities.

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company, in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics,and other desirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:056, Section 14(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. Company shall be held harmless for any damages or economic loss resulting from such termination of service. If requested by Company, Customer shall provide all available information to Company that aids Company in enforcing its service standards. If Company at any time has a reasonable basis for believing that Customer's proposed or existing use of the service provided will not comply with the service standards for interference, fluctuations, or harmonics, Company may engage such experts and/or consultants as Company shall determine are appropriate to advise Company in ensuring that such interference, fluctuations, or harmonics are within acceptable standards. Should such experts and/or consultants determine Customer's use of service is unacceptable, Company's use of such experts and/or consultants will be at the Customer's expense.

RATE

1. A contribution in aid of construction or an excess facilities charge shall be required for all special or added facilities, if any, necessary to serve such loads, as provided under the Excess Facilities Rider.
2. Plus the charges provided for under the rate schedule applicable, including any Basic Service Charge if applicable, Energy Charge, Maximum Load Charge (if load charge rate is used), Fuel Clause and the Minimum Charge under such rate adjusted in accordance with (a) or (b) herein.
   (a) If rate schedule calls for a minimum based on the total kW of connected load, each kVA of such special equipment shall be counted as one kW connected load for minimum billing purposes.
   (b) If rate schedule calls for a minimum based on the 15-minute integrated load, and such loads operate only intermittently so that the kW registered on a standard 15-minute integrated demand meter is small in comparison to the instantaneous load such equipment is capable of imposing, each kVA of such special equipment shall be counted as one-third kW load for minimum billing purposes.

MINIMUM CHARGE

As determined by this Rider and the Rate Schedule to which it is attached.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 65

Standard Rate Rider IL

Rider for Intermittent Loads

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule applies to all loads having a detrimental effect upon the electric service rendered to other customers of Company or upon Company's facilities.

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company, in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other desirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 14(1)(b). Such a termination of service T
shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. Company shall be held harmless for any damages or economic loss resulting from such termination of service. If requested by Company, Customer shall provide all available information to Company that aids Company in enforcing its service standards. If Company at any time has a reasonable basis for believing that Customer's proposed or existing use of the service provided will not comply with the service standards for interference, fluctuations, or harmonics, Company may engage such experts and/or consultants as Company shall determine are appropriate to advise Company in ensuring that such interference, fluctuations, or harmonics are within acceptable standards. Should such experts and/or consultants determine Customer's use of service is unacceptable, Company's use of such experts and/or consultants will be at the Customer's expense.

RATE

1. A contribution in aid of construction or an excess facilities charge shall be required for all special or added facilities, if any, necessary to serve such loads, as provided under the Excess Facilities Rider.
2. Plus the charges provided for under the rate schedule applicable, including any Basic Service Charge if applicable, Energy Charge, Maximum Load Charge (if load charge rate is used), Fuel Clause and the Minimum Charge under such rate adjusted in accordance with (a) or (b) herein.
   (a) If rate schedule calls for a minimum based on the total kW of connected load, each kVA of such special equipment shall be counted as one kW connected load for minimum billing purposes.
   (b) If rate schedule calls for a minimum based on the 15-minute integrated load, and such loads operate only intermittently so that the kW registered on a standard 15-minute integrated demand meter is small in comparison to the instantaneous load such equipment is capable of imposing, each kVA of such special equipment shall be counted as one-third kW load for minimum billing purposes.

MINIMUM CHARGE

As determined by this Rider and the Rate Schedule to which it is attached.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 66

Standard Rate Rider TS

Temporary and/or Seasonal Electric Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rider is available at the option of Customer where Customer's business is of such nature to require:

1. only seasonal service or temporary service, including service provided for construction of residences or commercial buildings, and where in the judgment of Company the local and system electrical facility capacities are adequate to serve the load without impairment of service to other customers; or
2. where Customer has need for temporary use of Company facilities and Company has facilities it is willing to provide.

This service is available for not less than one (1) month (approximately thirty (30) days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes.

CONDITIONS
Company may permit such electric loads to be served on the rate schedule normally applicable, but without requiring a yearly contract and minimum, substituting therefor the following conditions and agreements:

1. Customer shall pay Company for all costs of making temporary connections, including cost of installing necessary transformers, meters, poles, wire and any other material, and any cost of material which cannot be salvaged, and the cost of removing such facilities when load has ceased.

2. Customer shall pay regular rate of the applicable electric rate schedule.

3. Where Customer is receiving service under a standard rate and has need for temporary use of Company facilities, Customer will pay for non-savable materials outlined in (1) above at the Carrying Cost Charge specified on the Excess Facilities Rider, Rate Sheet No. 60.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 66

Standard Rate Rider TS

Temporary and/or Seasonal Electric Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rider is available at the option of Customer where Customer's business does not require T
permanent installation of Company's facilities and is of such nature to require: T

1. only seasonal service or temporary service, including service provided for construction of residences or commercial buildings, and where in the judgment of Company the local and system electrical facility capacities are adequate to serve the load without impairment of service to other customers; or
2. where Customer has need for temporary use of Company facilities and Company has facilities it is willing to provide.

This service is available for not less than one (1) month (approximately thirty (30) days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes.

CONDITIONS
Company may permit such electric loads to be served on the rate schedule normally applicable, but without requiring a yearly contract and minimum, substituting therefor the following conditions and agreements:

1. Customer shall pay Company for all costs of making temporary connections, including cost of installing necessary transformers, meters, poles, wire and any other material, and any cost of material which cannot be salvaged, and the cost of removing such facilities when load has ceased.

2. Customer shall pay regular rate of the applicable electric rate schedule.

3. Where Customer is receiving service under a standard rate and has need for temporary use of Company facilities, Customer will pay for non-salvageable materials outlined in (1) above T
plus a monthly charge for the salvageable equipment at the Percentage With No Contribution T
-in-Aid-of-Construction specified on the Excess Facilities Rider, Rate Sheet No. 60. T

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 67

Standard Rate Rider

Kilowatt-Hours Consumed By Lighting Units

APPLICABLE

Determination of energy set out below applies to the Company's non-metered lighting rate schedules.

DETERMINATION OF ENERGY CONSUMPTION

The applicable fuel clause charge or credit will be based on the kilowatt-hours calculated by multiplying the kilowatt load of each light times the number of hours that light is in use during the billing month. The kilowatt load of each light is shown in the section titled RATE. The number of hours a light will be in use during a given month is from dusk to dawn as shown in the following Hours Use Table.

HOURS USE TABLE

Month	Hours Light Is In Use
JAN	407
FEB	344
MAR	347
APR	301
MAY	281
JUN	257
JUL	273
AUG	299
SEP	322
OCT	368
NOV	386
DEC	415
TOTAL FOR YEAR	4,000 HRS.

Date of Issue: August 6, 2010
Date Effective: March 1, 2000
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 67

Standard Rate Rider

Kilowatt-Hours Consumed By Lighting Units

APPLICABLE

Determination of energy set out below applies to the Company's non-metered lighting rate schedules.

DETERMINATION OF ENERGY CONSUMPTION

The applicable fuel clause charge or credit will be based on the kilowatt-hours calculated by multiplying the kilowatt load of each light times the number of hours that light is in use during the billing month. The kilowatt load of each light is shown in the section titled RATE. The number of hours a light will be in use during a given month is from dusk to dawn as shown in the following Hours Use Table.

HOURS USE TABLE

Month	Hours Light Is In Use
JAN	407
FEB	344
MAR	347
APR	301
MAY	281
JUN	257
JUL	273
AUG	299
SEP	322
OCT	368
NOV	386
DEC	415
TOTAL FOR YEAR	4,000 HRS.

Date of Issue: June 29, 2012
Date Effective: March 1, 2000
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 70

Standard Rate Rider SGE

Small Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard RS or GS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.

b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one (1) MWh of green power.

RATE

Voluntary monthly contributions of any amount in $5.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $5.00 increments (e.g., $5.00, $10.00, $15.00, or more per month). An eligible customer may participate in Company's "Green Energy Program" by making a request to Company's Call Center or through Company's website enrollment form and may withdraw at any time through a request to Company's Call Center. Funds provided by Customer to Company are not refundable.

b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any Customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one (1) year.

c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

Date of Issue: August 6, 2010
Date Effective: June 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00467 dated February 22, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 70

Standard Rate Rider SGE

Small Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard RS or GS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.

b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one (1) MWh of green power.

RATE

Voluntary monthly contributions of any amount in $5.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $5.00 increments (e.g., $5.00, $10.00, $15.00, or more per month). An eligible customer may participate in Company's "Green Energy Program" by making a request to Company's Call Center or through Company's website enrollment form and may withdraw at any time through a request to Company's Call Center. Funds provided by Customer to Company are not refundable.

b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any Customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one (1) year.

c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

Date of Issue: June 29, 2012
Date Effective: June 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00467 dated February 22, 2010

Standard Rate Rider LGE

Large Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard PS, TOD, RTS, or IS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.

b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one (1) MWh of green power.

RATE

Voluntary monthly contributions of any amount in $13.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $13.00 increments, (e.g., $13.00, $26.00, $39.00, or more per month). An eligible customer may participate in company's "Green Energy Program" by making a request to the Company and may withdraw at any time through a request to the Company. Funds provided by Customer to Company are not refundable.

b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one (1) year.

c) Customer will be billed monthly for the amount customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

Standard Rate Rider LGE

Large Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard PS, TODS, TODP, RTS, or FLS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates. T

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.

b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one (1) MWh of green power.

RATE

Voluntary monthly contributions of any amount in $13.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $13.00 increments, (e.g., $13.00, $26.00, $39.00, or more per month). An eligible customer may participate in company's "Green Energy Program" by making a request to the Company and may withdraw at any time through a request to the Company. Funds provided by Customer to Company are not refundable.

b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one (1) year.

c) Customer will be billed monthly for the amount customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 71
Canceling P.S.C. No. 15, Original Sheet No. 71

Standard Rate Rider — EDR
Economic Development Rider

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available as a rider to customers to be served or being served under Company's Standard Rate Schedules TODS, TODP, and RTS to encourage Brownfield Development or Economic Development (as defined herein). Service under EDR is conditional on approval of a special contract for such service filed with and approved by the Public Service Commission of Kentucky.

RATE
A customer taking service under EDR shall be served according to all of the rates, terms, and conditions of the normally applicable rate schedule subject to the following:

a) for the twelve consecutive monthly billings of the first contract year, the Total Demand Charge shall be reduced by 50%;
b) for the twelve consecutive monthly billings of the second contract year, the Total Demand Charge shall be reduced by 40%;
c) for the twelve consecutive monthly billings of the third contract year, the Total Demand Charge shall be reduced by 30%;
d) for the twelve consecutive monthly billings of the fourth contract year, the Total Demand Charge shall be reduced by 20%;
e) for the twelve consecutive monthly billings of the fifth contract year, the Total Demand Charge shall be reduced by 10%; and
f) all subsequent billing shall be at the full charges stated in the applicable rate schedule.

"Total Demand Charge" is the sum of all demand charges, including any credits provided under any other demand applicable rider, before the EDR discounts described above are applied.

TERMS AND CONDITIONS
Brownfield Development
a) Service under EDR for Brownfield Development is available to customers locating at sites that have been submitted to, approved by, and added to the Brownfield Inventory maintained by the Kentucky Energy and Environment Cabinet (or by any successor entity created and authorized by the Commonwealth of Kentucky).
b) EDR for Brownfield Development is available only to billing loads of 500 kVA or greater where the customer takes service from existing Company facilities.

Economic Development
c) Service under EDR for Economic Development is available to:
   1) new customers contracting for a minimum annual average of monthly billing load of 1,000 kVA; and
   2) existing customers contracting for a minimum annual average of monthly billing load of 1,000 kVA above their Existing Base Load, to be determined as follows:

Date of Issue: August 19, 2011
Date Effective: August 11, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00103 dated August 11, 2011

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 71

Standard Rate Rider — EDR
Economic Development Rider

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available as a rider to customers to be served or being served under Company's Standard Rate Schedules TODS, TODP, and RTS to encourage Brownfield Development or Economic Development (as defined herein). Service under EDR is conditional on approval of a special contract for such service filed with and approved by the Public Service Commission of Kentucky.

RATE
A customer taking service under EDR shall be served according to all of the rates, terms, and conditions of the normally applicable rate schedule subject to the following:

a) for the twelve consecutive monthly billings of the first contract year, the Total Demand Charge shall be reduced by 50%;
b) for the twelve consecutive monthly billings of the second contract year, the Total Demand Charge shall be reduced by 40%;
c) for the twelve consecutive monthly billings of the third contract year, the Total Demand Charge shall be reduced by 30%;
d) for the twelve consecutive monthly billings of the fourth contract year, the Total Demand Charge shall be reduced by 20%;
e) for the twelve consecutive monthly billings of the fifth contract year, the Total Demand Charge shall be reduced by 10%; and
f) all subsequent billing shall be at the full charges stated in the applicable rate schedule.

"Total Demand Charge" is the sum of all demand charges, including any credits provided under any other demand applicable rider, before the EDR discounts described above are applied.

TERMS AND CONDITIONS
Brownfield Development
a) Service under EDR for Brownfield Development is available to customers locating at sites that have been submitted to, approved by, and added to the Brownfield Inventory maintained by the Kentucky Energy and Environment Cabinet (or by any successor entity created and authorized by the Commonwealth of Kentucky).
b) EDR for Brownfield Development is available only to billing loads of 500 kVA or greater where the customer takes service from existing Company facilities.

Economic Development
c) Service under EDR for Economic Development is available to:
   1) new customers contracting for a minimum annual average of monthly billing load of 1,000 kVA; and
   2) existing customers contracting for a minimum annual average of monthly billing load of 1,000 kVA above their Existing Base Load, to be determined as follows:

Date of Issue: June 29, 2012
Date Effective: August 11, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00103 dated August 11, 2011

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 71.1

Standard Rate Rider **EDR**
Economic Development Rider

TERMS AND CONDITIONS, Economic Development c) 2) (continued)

i. Company and the existing customer will determine Customer's Existing Base Load by averaging Customer's previous three years' monthly billing loads, subject to any mutually agreed upon adjustments thereto.
ii. Company and the existing customer must agree upon the Existing Base Load, which shall be an explicit term of the special contract submitted to the Commission for approval before the customer can take service under EDR. Once the Existing Base Load's value is thus established, it will not be subject to variation or eligible for service under EDR.
iii. This provision is not intended to reduce or diminish in any way EDR service already being provided to all or a portion of a customer's Existing Base Load. Such EDR service would continue under the terms of the contract already existing between the Company and the customer concerning the affected portion of the customer's Existing Base Load.

d) A customer desiring service under EDR for Economic Development must submit an application for service that includes:
  1) a description of the new load to be served;
  2) the number of new employees, if any, Customer anticipates employing associated with the new load;
  3) the capital investment Customer anticipates making associated with the EDR load;
  4) a certification that Customer has been qualified by the Commonwealth of Kentucky for benefits under the Kentucky Business Investment Program.

e) Should Company determine a refundable contribution for the capital investment in Customer-specific facilities required by Company to serve the EDR load would ordinarily be required as set out under Company's Line Extension Plan, I. Special Cases, that amount shall be determined over a fifteen (15) year period and payable at the end of the fifteen (15) year period.

General

f) Company may offer EDR to qualifying new load only when Company has generating capacity available and the new load will not accelerate Company's plans for additional generating capacity over the life of the EDR contract.
g) Customer may request an EDR effective initial billing date that is no later than twelve (12) months after the date on which Company initiates service to Customer.
h) Neither the demand charge reduction nor any unjustified capital investment in facilities will be borne by Company's other customers during the term of the EDR contract.
i) Company may offer differing terms, as appropriate, under special contract to which this rider is a part depending on the circumstances associated with providing service to a particular customer and subject to approval by the Public Service Commission of Kentucky.

TERM OF CONTRACT

Service will be furnished under the applicable standard rate schedule and this rider, filed as a special contract with the Commission for a fixed term of not less than ten (10) years and for such time thereafter under the terms stated in the standard rate schedule. A greater term of contract or termination notice may be required because of conditions associated with a Customer's requirements for service. Service will be continued under conditions provided for under the rate schedule to which this Rider is attached after the original term of contract.

Date of Issue: August 19, 2011
Date Effective: August 11, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00103 dated August 11, 2011

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 71.1

Standard Rate Rider **EDR**
Economic Development Rider

TERMS AND CONDITIONS, Economic Development c) 2) (continued)

i. Company and the existing customer will determine Customer's Existing Base Load by averaging Customer's previous three years' monthly billing loads, subject to any mutually agreed upon adjustments thereto.
ii. Company and the existing customer must agree upon the Existing Base Load, which shall be an explicit term of the special contract submitted to the Commission for approval before the customer can take service under EDR. Once the Existing Base Load's value is thus established, it will not be subject to variation or eligible for service under EDR.
iii. This provision is not intended to reduce or diminish in any way EDR service already being provided to all or a portion of a customer's Existing Base Load. Such EDR service would continue under the terms of the contract already existing between the Company and the customer concerning the affected portion of the customer's Existing Base Load.

d) A customer desiring service under EDR for Economic Development must submit an application for service that includes:
  1) a description of the new load to be served;
  2) the number of new employees, if any, Customer anticipates employing associated with the new load;
  3) the capital investment Customer anticipates making associated with the EDR load;
  4) a certification that Customer has been qualified by the Commonwealth of Kentucky for benefits under the Kentucky Business Investment Program.

e) Should Company determine a refundable contribution for the capital investment in Customer-specific facilities required by Company to serve the EDR load would ordinarily be required as set out under Company's Line Extension Plan, I. Special Cases, that amount shall be determined over a fifteen (15) year period and payable at the end of the fifteen (15) year period.

General

f) Company may offer EDR to qualifying new load only when Company has generating capacity available and the new load will not accelerate Company's plans for additional generating capacity over the life of the EDR contract.
g) Customer may request an EDR effective initial billing date that is no later than twelve (12) months after the date on which Company initiates service to Customer.
h) Neither the demand charge reduction nor any unjustified capital investment in facilities will be borne by Company's other customers during the term of the EDR contract.
i) Company may offer differing terms, as appropriate, under special contract to which this rider is a part depending on the circumstances associated with providing service to a particular customer and subject to approval by the Public Service Commission of Kentucky.

TERM OF CONTRACT

Service will be furnished under the applicable standard rate schedule and this rider, filed as a special contract with the Commission for a fixed term of not less than ten (10) years and for such time thereafter under the terms stated in the standard rate schedule. A greater term of contract or termination notice may be required because of conditions associated with a Customer's requirements for service. Service will be continued under conditions provided for under the rate schedule to which this Rider is attached after the original term of contract.

Date of Issue: June 29, 2012
Date Effective: August 11, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00103 dated August 11, 2011

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 78
Canceling P.S.C. No. 15, Original Sheet No. 78

Standard Rate Rider	RTP
	Real-Time Pricing Rider

APPLICABLE

In all territory served by the Company.

AVAILABILITY OF SERVICE

RTP shall be offered as an optional three (3) year pilot program and is available as a rider to the Company's P.S.C. No. 13, LTOD, or IS rate schedules for customers having received service under those schedules for a minimum of one (1) year as of December 1, 2008. Service will be provided under RTP following its approval and shall remain in effect until modified or terminated by order of the Commission.

a) No customers will be accepted on RTP after the Company files with the Commission notice of its intent to file a base rate case in accordance with the terms of the Stipulation and Recommendation in P.S.C. Case No. 2009-00548. A customer exiting the pilot program or disconnected for non-pay will not be allowed to return to it until the Commission has issued a final order in that base rate case.

b) The Company will file with the Commission a detailed report of its findings and recommendations concerning the RTP pilot program in its next base rate case.

c) Service under RTP may not be taken in conjunction with any other load reduction riders such as but not limited to CSR, LRI, or NMS.

BILLING

Customers participating in the RTP Pilot will be billed monthly based on the following calculation:

$$\text{RTP Bill} = SB + PC + \sum_{t=1}^{n} \{ \text{Price}_t \times (AL_t - CBL_t) \}$$

Where:

RTP Bill	=	Customer's bill for service under this tariff in a specific month.
SB	=	Customer's bill for the current billing period based on current usage and billed under the appropriate standard rate schedule.
PC	=	Customer specific program charge.
$\sum_{t=1}^{n}$	=	Sum of all hours of the billing period from t=1 to n.
Price_t	=	Real-time day-ahead marginal generation supply cost for hour t.
AL_t	=	Customer's actual kVA load for hour t.
CBL_t	=	Customer's baseline kVA load for hour t.

HOURLY PRICING

Hourly prices (Price_t) are determined each day based on projections of the marginal generation supply cost for the next day and adjusted for losses to the customer's delivery voltage. Hourly prices will be provided on a day-ahead basis to Customer. The Company may revise these prices the day before they become effective. Prices become binding at 4:00 p.m. of the preceding day. Service under RTP will require customer enter into a confidentiality agreement with the Company to protect the day ahead hourly prices.

Date of Issue: April 9, 2012
Date Effective: April 9, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00010 dated March 20, 2012

The current KU Real-Time Pricing Rider RTP is proposed to be eliminated.

Standard Rate Rider RTP

Real-Time Pricing Rider

CUSTOMER BASELINE LOAD (CBL)

The CBL is based on one complete calendar year of hourly firm kVA load data developed from actual historical metered interval data for the Customer's specific service delivery and mutually agreed to by Customer and Company. The CBL is determined by:

1. selecting the historical calendar period that corresponds to the current billing period,
2. shifting the historical calendar period back no more than 4 days or forward until the days of the week agree for the historical calendar period and the current billing period, and
3. adjusting on a pro rata basis each hour of the historical calendar period so that the sum of the hourly kVA loads for the historical calendar period matches the sum of the hourly kVA loads for the current billing period.

PROGRAM CHARGE (PC)

A program charge of $57 per billing period shall be added to the Customer's bill to cover the additional customer specific costs associated with the program.

MINIMUM CHARGE

The minimum charge in the applicable Standard Tariff shall apply plus PC, customer specific program charge.

TERMS OF CONTRACT

For a fixed term of not less than one year and for such time thereafter until terminated by either party giving 30 days written notice to the other of the desire to terminate.

TERMS AND CONDITIONS

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

Date of Issue: May 3, 2012
Date Effective: April 9, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00010 dated March 20, 2012

The current KU Real-Time Pricing Rider RTP is proposed to be eliminated.

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 79
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 79

Standard Rate — LEV
Low Emission Vehicle Service

APPLICABLE
In the territory served.

AVAILABILITY OF SERVICE
LEV shall be available as option to customers otherwise served under rate schedule RS to encourage off-peak power for low emission vehicles.

1) LEV is a three year pilot program that may be restricted to a maximum of one hundred (100) customers eligible for Rate RS in any year and shall remain in effect until modified or terminated by order of the Commission. Company will accept applications on a first-come-first-served basis.
2) This service is restricted to customers who demonstrate power delivered to premises is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include:
   a) battery electric vehicles or plug-in hybrid electric vehicles recharged through a charging outlet at Customer's premises,
   b) natural gas vehicles refueled through an electric-powered refueling appliance at Customer's premises.
3) A customer exiting the pilot program or disconnected for non-payment may not be allowed to return to it until the Commission has issued a decision on the pilot program report.
4) Company will file a report on LEV with the Commission within six months after the first three years of implementation of the pilot program. Such report will detail findings and recommendations.

RATE

Basic Service Charge:	$ 8.50 per month
Plus an Energy Charge:	
Off Peak Hours:	$ 0.04904 per kWh
Intermediate Hours:	$ 0.07005 per kWh
Peak Hours:	$ 0.13315 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

Date of Issue: February 17, 2012
Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00231 dated January 31, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 79

Standard Rate — LEV
Low Emission Vehicle Service

APPLICABLE
In the territory served.

AVAILABILITY OF SERVICE
LEV shall be available as option to customers otherwise served under rate schedule RS to encourage off-peak power for low emission vehicles.

1) LEV is a three year pilot program that may be restricted to a maximum of one hundred (100) customers eligible for Rate RS (or GS where the GS service is used in conjunction with an RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month) in any year and shall remain in effect until modified or terminated by order of the Commission. Company will accept applications on a first-come-first-served basis. T T T
2) This service is restricted to customers who demonstrate power delivered to premises is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include:
   a) battery electric vehicles or plug-in hybrid electric vehicles recharged through a charging outlet at Customer's premises,
   b) natural gas vehicles refueled through an electric-powered refueling appliance at Customer's premises.
3) A customer exiting the pilot program or disconnected for non-payment may not be allowed to return to it until the Commission has issued a decision on the pilot program report.
4) Company will file a report on LEV with the Commission within six months after the first three years of implementation of the pilot program. Such report will detail findings and recommendations.

RATE

Basic Service Charge:	$13.00 per month	I
Plus an Energy Charge:		
Off Peak Hours:	$0.05078 per kWh	I
Intermediate Hours:	$0.07254 per kWh	I
Peak Hours:	$0.13788 per kWh	I

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 79.1

Standard Rate — LEV
Low Emission Vehicle Service

DETERMINATION OF PRICING PERIODS
Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends. The hours of the pricing periods for the price levels are as follows:

Summer months of May through September

	Off-Peak	Intermediate	Peak
Weekdays	10 PM - 10 AM	10 AM - 1 PM 7 PM - 10 PM	1 PM - 7 PM
Weekends	All Hours		

All other month of October continuously through April

	Off Peak	Intermediate	Peak
Weekdays	10 PM - 6 AM	12 Noon – 10 PM	6 AM – 12 Noon
Weekends	All Hours		

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month's charges.

TERMS OF CONTRACT
For a fixed term of not less than one (1) year and for such time thereafter until terminated by either party giving thirty (30) days written notice to the other of the desire to terminate.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional pilot program will not be eligible for Company's Budget Payment Plan. Company shall install metering equipment capable of accommodating the Time of Use rate described herein.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 79.1

Standard Rate — LEV
Low Emission Vehicle Service

DETERMINATION OF PRICING PERIODS
Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends. The hours of the pricing periods for the price levels are as follows:

Summer Months of May through September

	Off-Peak	Intermediate	Peak
Weekdays	10 PM - 10 AM	10 AM - 1 PM 7 PM - 10 PM	1 PM - 7 PM
Weekends	All Hours		

All Other Months of October continuously through April

	Off Peak	Intermediate	Peak
Weekdays	10 PM - 6 AM	12 Noon – 10 PM	6 AM – 12 Noon
Weekends	All Hours		

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within twelve (12) calendar days from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received within three (3) calendar days from the due date of the bill, a 5% late payment charge will be assessed on the current month's charges.

TERMS OF CONTRACT
For a fixed term of not less than one (1) year and for such time thereafter until terminated by either party giving thirty (30) days written notice to the other of the desire to terminate.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional pilot program will not be eligible for Company's Budget Payment Plan. Company shall install metering equipment capable of accommodating the Time of Use rate described herein.

Date of Issue: June 29, 2012
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 85

Adjustment Clause FAC

Fuel Adjustment Clause

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all electric rate schedules.

(1) The charge per kWh delivered under the rate schedules to which this fuel clause is applicable shall be increased or decreased during each month in accordance with the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

where "F" is the expense of fossil fuel and "S" is the kWh sales in the base (b) and current (m) periods as defined in 807 KAR 5:056, all as set out below.

(2) Fuel costs (F) shall be the most recent actual monthly cost of:

(a) Fossil fuel consumed in the utility's own plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation; plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute for the forced outages; plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) The cost of fossil fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(e) All fuel costs shall be based on weighted average inventory costing.

(3) Forced outages are all non-schedules losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel cost of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel cost (F) in subsection (2)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

Date of Issue: August 6, 2010
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 85

Adjustment Clause FAC

Fuel Adjustment Clause

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all electric rate schedules.

(1) The charge per kWh delivered under the rate schedules to which this fuel clause is applicable shall be increased or decreased during each month in accordance with the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

where "F" is the expense of fossil fuel and "S" is the kWh sales in the base (b) and current (m) periods as defined in 807 KAR 5:056, all as set out below.

(2) Fuel costs (F) shall be the most recent actual monthly cost of:

(a) Fossil fuel consumed in the utility's own plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation; plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute for the forced outages; plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) The cost of fossil fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(e) All fuel costs shall be based on weighted average inventory costing.

(3) Forced outages are all non-scheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel cost of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel cost (F) in subsection (2)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation. T

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 85.1
Canceling P.S.C. No. 15, Original Sheet No. 85.1

Adjustment Clause FAC
Fuel Adjustment Clause

(4) Sales (S) shall be all kWh's sold, excluding inter-system sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) inter-system sales referred to in subsection (2)(d) above, less (vi) total system losses. Utility used energy shall not be excluded in the determination of sales (S).

(5) The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees.

(6) Base (b) period shall be the twelve (12) months ending October 2010 and the base fuel factor is \$0.02668 per kWh.

(7) Current (m) period shall be the second month preceding the month in which the Fuel Clause Adjustment Factor is billed.

(8) Pursuant to the Public Service Commission's Order in Case No. 2010-00492 dated May 31, 2011, the Fuel Adjustment Clause will become effective with bills rendered on and after the first billing cycle for July 2011, which begins June 29, 2011.

Date of Issue: June 10, 2011
Date Effective: With Bills Rendered On and After June 29, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2010-00492 dated May 30, 2011

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 85.1

Adjustment Clause FAC
Fuel Adjustment Clause

(4) Sales (S) shall be all kWh sold, excluding inter-system sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) inter-system sales referred to in subsection (2)(d) above, less (vi) total system losses. Utility used energy shall not be excluded in the determination of sales (S). T

(5) The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees.

(6) Base (b) period shall be the twelve (12) months ending October 2010 and the base fuel factor is \$0.02668 per kWh.

(7) Current (m) period shall be the second month preceding the month in which the Fuel Clause Adjustment Factor is billed.

(8) Pursuant to the Public Service Commission's Order in Case No. 2010-00492 dated May 31, 2011, the Fuel Adjustment Clause will become effective with bills rendered on and after the first billing cycle for July 2011, which begins June 29, 2011.

Date of Issue: June 29, 2012
Date Effective: With Bills Rendered On and After June 29, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2010-00492 dated May 30, 2011

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 86
Canceling P.S.C. No. 15, Original Sheet No. 86

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to Residential Rate RS, Volunteer Fire Department Service Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Low Emission Vehicle Service Rider LEV. Industrial customers who elect not to participate in a demand-side management program hereunder shall not be assessed a charge pursuant to this mechanism. For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are primarily engaged in a process or processes that create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32, and 33. All other non-residential customers will be defined as "commercial."

RATE

The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per kilowatt hour of monthly consumption in accordance with the following formula:

$$DSMRC = DCR + DRLS + DSMI + DBA + DCCR$$

Where:

DCR = DSM COST RECOVERY

The DCR shall include all expected costs that have been approved by the Commission for each twelve-month period for demand-side management programs that have been developed through a collaborative advisory process ("approved programs"). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs. Program costs will be assigned for recovery purposes to the rate classes whose customers are directly participating in the program. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees, and administrative expenses, will be recovered through the DCR. Administrative costs that are allocable to more than one rate class will be recovered from those classes and allocated by rate class on the basis of the estimated budget from each program. The cost of approved programs shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DCR for each such rate class.

DRLS = DSM REVENUE FROM LOST SALES

Revenues from lost sales due to DSM programs implemented on and after the effective date of this tariff will be recovered as follows:

1) For each upcoming twelve-month period, the estimated reduction in customer usage (in kWh) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per kWh for purposes of determining the lost revenue to be recovered hereunder from each customer class. The non-variable revenue requirement for the Residential, Volunteer Fire Department, General Service, All Electric School, and Low Emission Vehicle customer classes is defined as the weighted average price per kWh of expected billings under the energy charges contained in the

Date of Issue: November 29, 2011
Date Effective: December 30, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00134 dated November 9, 2011

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 86

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to Residential Rate RS, Volunteer Fire Department Service Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Low Emission Vehicle Service Rate LEV. Industrial customers who elect not to participate in a T
demand-side management program hereunder shall not be assessed a charge pursuant to this mechanism. For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are primarily engaged in a process or processes that create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32, and 33. All other non-residential customers will be defined as "commercial."

RATE

The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per kilowatt hour of monthly consumption in accordance with the following formula:

$$DSMRC = DCR + DRLS + DSMI + DBA + DCCR$$

Where:

DCR = DSM COST RECOVERY

The DCR shall include all expected costs that have been approved by the Commission for each twelve-month period for demand-side management programs that have been developed through a collaborative advisory process ("approved programs"). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs. Program costs will be assigned for recovery purposes to the rate classes whose customers are directly participating in the program. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees, and administrative expenses, will be recovered through the DCR. Administrative costs that are allocable to more than one rate class will be recovered from those classes and allocated by rate class on the basis of the estimated budget from each program. The cost of approved programs shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DCR for each such rate class.

DRLS = DSM REVENUE FROM LOST SALES

Revenues from lost sales due to DSM programs implemented on and after the effective date of this tariff will be recovered as follows:

1) For each upcoming twelve-month period, the estimated reduction in customer usage (in kWh) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per kWh for purposes of determining the lost revenue to be recovered hereunder from each customer class. The non-variable revenue requirement for the Residential, Volunteer Fire Department, General Service, All Electric School, and Low Emission Vehicle customer classes is defined as the weighted average price per kWh of expected billings under the energy charges contained in the

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 86.1
Canceling P.S.C. No. 15, Original Sheet No. 86.1

Adjustment Clause DSM
Demand-Side Management Cost Recovery Mechanism

RATE (continued)

RS, VFD, GS, AES, and LEV rate schedules in the upcoming twelve-month period after deducting the variable costs included in such energy charges. The non-variable revenue requirement for each of the customer classes that are billed under demand and energy rates (rate schedules PS, TODS, and TODP) is defined as the weighted average price per kWh represented by the composite of the expected billings under the respective demand and energy charges in the upcoming twelve-month period, after deducting the variable costs included in the energy charges.

2) The lost revenues for each customer class shall then be divided by the estimated class sales (in kWh) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenue from lost sales calculated for a twelve-month period shall be included in the DRLS for 36 months or until implementation of new rates pursuant to a general rate case, whichever comes first. Revenues from lost sales will be assigned for recovery purposes to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation, and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

DSMI = DSM INCENTIVE

For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved programs that are to be installed during the upcoming twelve-month period times fifteen (15) percent, not to exceed five (5) percent of program expenditures. Net resource savings are defined as program benefits less utility program costs and participant costs where program benefits will be calculated on the basis of the present value of Company's avoided costs over the expected life of the program, and will include both capacity and energy savings. For the Energy Education Program, the DSM incentive amount shall be computed by multiplying the annual cost of the approved program times five (5) percent.

The DSM incentive amount related to programs for Residential Rate RS, Volunteer Fire Department Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Rate PS, Time-of-day Secondary Service Rate TODS, Time-of-Day Primary Rate TODP, and Low Emission Vehicle Service Rider LEV shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DSMI for such rate class. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

Date of Issue: November 29, 2011
Date Effective: December 30, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00134 dated November 9, 2011

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 86.1

Adjustment Clause DSM
Demand-Side Management Cost Recovery Mechanism

RATE (continued)

RS, VFD, GS, AES, and LEV rate schedules in the upcoming twelve-month period after deducting the variable costs included in such energy charges. The non-variable revenue requirement for each of the customer classes that are billed under demand and energy rates (rate schedules PS, TODS, and TODP) is defined as the weighted average price per kWh represented by the composite of the expected billings under the respective demand and energy charges in the upcoming twelve-month period, after deducting the variable costs included in the energy charges.

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Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation, and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

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The DSM incentive amount related to programs for Residential Rate RS, Volunteer Fire Department Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Rate PS, Time-of-day Secondary Service Rate TODS, Time-of-Day Primary Rate TODP, and Low Emission Vehicle Service Rate LEV shall be divided by the expected kilowatt-hour sales for T the upcoming twelve-month period to determine the DSMI for such rate class. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

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Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 86.2
Canceling P.S.C. No. 15, Original Sheet No. 86.2

Adjustment Clause DSM
Demand-Side Management Cost Recovery Mechanism

DBA = DSM BALANCE ADJUSTMENT

The DBA shall be calculated on a calendar-year basis and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, DCCR, and previous application of the DBA and the revenues that should have been billed, as follows:

1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.
2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.
3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.
4) For the DBA, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DBA and the balance adjustment amount established for the same twelve-month period.

The balance adjustment amounts determined on the basis of the above paragraphs (1)-(4) shall include interest applied to the monthly amounts, such interest to be calculated at a rate equal to the average of the "Three-Month Commercial Paper Rate" for the immediately preceding twelve-month period. The total of the balance adjustment amounts shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DBA for such rate class. DSM balance adjustment amounts will be assigned for recovery purposes to the rate classes for which over- or under-recoveries of DSM amounts were realized.

DCCR = DSM CAPITAL COST RECOVERY

The DCCR component is the means by which the Company recovers its capital investments made for DSM programs, as well as an approved rate of return on such capital investments. The Company calculates the DCCR component as follows:

DCCR = [(RB) (ROR + (ROR – DR) (TR / (1 – TR))] + OE

a) RB is the total rate base for DCCR projects.
b) ROR is the overall rate of return on DSM Rate Base (RB).
c) DR is the composite debt rate (i.e., the cost of short- and long-term debt) embedded in ROR.
d) TR is the composite federal and state income tax rate that applies to the equity return component of ROR.
e) OE is the sum of the capital-related operating expenses (i.e., depreciation and amortization expense, property taxes, and insurance expense) of the DSM projects to which DCCR applies.

Date of Issue: November 29, 2011
Date Effective: December 30, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00134 dated November 9, 2011

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 86.2

Adjustment Clause DSM
Demand-Side Management Cost Recovery Mechanism

DBA = DSM BALANCE ADJUSTMENT

The DBA shall be calculated on a calendar-year basis and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, DCCR, and previous application of the DBA and the revenues that should have been billed, as follows:

1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.
2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.
3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.
4) For the DBA, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DBA and the balance adjustment amount established for the same twelve-month period.

The balance adjustment amounts determined on the basis of the above paragraphs (1)-(4) shall include interest applied to the monthly amounts, such interest to be calculated at a rate equal to the average of the "Three-Month Commercial Paper Rate" for the immediately preceding twelve-month period. The total of the balance adjustment amounts shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DBA for such rate class. DSM balance adjustment amounts will be assigned for recovery purposes to the rate classes for which over- or under-recoveries of DSM amounts were realized.

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Date of Issue: June 29, 2012
Date Effective: December 30, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00134 dated November 9, 2011

Adjustment Clause DSM
Demand-Side Management Cost Recovery Mechanism

The Company then allocates the DCCR component to the rate class(es) benefitting from the Company's various DSM-related capital investment(s).

CHANGES TO DSMRC

Modifications to other components of the DSMRC shall be made at least thirty days prior to the effective period for billing. Each filing shall include the following information as applicable:

1) A detailed description of each DSM program developed by the collaborative process, the total cost of each program over the twelve-month period, an analysis of expected resource savings, information concerning the specific DSM or efficiency measures to be installed, and any applicable studies that have been performed, as available.
2) A statement setting forth the detailed calculation of the DCR, DRLS, DSMI, DBA, DCCR, and DSMRC.

Each change in the DSMRC shall be placed into effect with bills rendered on and after the effective date of such change.

PROGRAMMATIC CUSTOMER CHARGES

Residential Customer Program Participation Incentives:
The following Demand Side Management programs are available to residential customers receiving service from the Company on the RS, VFD and LEV Standard Electric Rate Schedules.

Residential Load Management / Demand Conservation
The Residential Load Management / Demand Conservation Program employ switches in homes to help reduce the demand for electricity during peak times. The program communicates with the switches to cycle central air conditioning units, heat pumps, electric water heaters, and pool pumps off and on through a predetermined sequence. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

Residential Conservation / Home Energy Performance Program
The on-site audit offers a comprehensive audit from a certified auditor and incentives for residential customers to support the implementation of energy saving measures for a fee of $25. Customers are eligible for incentives of $500 or $1,000 based on customer purchased and installed energy efficiency measures and validated through a follow-up test.

Adjustment Clause DSM
Demand-Side Management Cost Recovery Mechanism

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Kentucky Utilities Company

P.S.C. No. 15, Third Revision of Original Sheet No. 86.4
Canceling P.S.C. No. 15, Second Revision of Original Sheet No. 86.4

Adjustment Clause DSM
Demand-Side Management Cost Recovery Mechanism

Residential Low Income Weatherization Program (WeCare)
The Residential Low Income Weatherization Program (WeCare) is an education and weatherization program designed to reduce energy consumption of LG&E's low-income customers. The program provides energy audits, energy education, blower door tests, and installs weatherization and energy conservation measures. Qualified customers could receive energy conservation measures ranging from $0 to $2,100 based upon the customer's most recent twelve month energy usage and results of an energy audit.

Smart Energy Profile
The Smart Energy Profile Program provides a portion of KU's highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar properties in locality. The report will help the customer understand and make better informed choices as it relates to energy usage and the associated costs. Information presented in the report will include a comparison of the customer's energy usage to that of similar houses (collectively) and a comparison to the customer's own energy usage in the prior year.

Residential Incentives Program
The Residential Incentives Program encourages customers to purchase and install various ENERGY STAR® appliances, HVAC equipment, or window films that meet certain requirements, qualifying them for an incentive as noted in the table below.

Category	Item	Incentive
Appliances	Heat Pump Water Heaters (HPWH)	$300 per qualifying item purchased
	Washing Machine	$75 per qualifying item purchased
	Refrigerator	$100 per qualifying item purchased
	Freezer	$50 per qualifying item purchased
	Dishwasher	$50 per qualifying item purchased
Window Film	Window Film	Up to 50% of materials cost only; max of $200 per customer account; product must meet applicable criteria.
HVAC	Central Air Conditioner	$100 per Energy Star item purchased plus an additional $100 per SEER improvement above minimum
	Electric Air-Source Heat Pump	$100 per Energy Star item purchased plus additional $100 per SEER improvement above minimum

Date of Issue: April 30, 2012
Date Effective: May 31, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 86.4

Adjustment Clause DSM
Demand-Side Management Cost Recovery Mechanism

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Date of Issue: June 29, 2012
Date Effective: May 31, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

Residential Refrigerator Removal Program
The Residential Refrigerator Removal Program is designed to provide removal and recycling of working, inefficient secondary refrigerators and freezers from KU customer households. Customers participating in this program will be provided a one-time incentive. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

Residential High Efficiency Lighting Program

The Residential High Efficiency Lighting program promotes an increased use of ENERGY STAR® rated CFLs within the residential sector. The Residential High Efficiency Lighting Program distributes compact fluorescent bulbs through direct-mail.

Residential New Construction Program
The Residential New Construction program is designed to reduce residential energy usage and facilitate market transformation by creating a shift in builders' new home construction to include energy-efficient construction practices. Builders who are part of the program can take advantage of technical training classes, gain additional exposure to potential customers and receive incentives to help offset costs when including more energy-efficient features during home construction. KU will reimburse the cost of plan reviews and inspection costs related to an Energy Star or HERS home certification.

Residential HVAC Diagnostics and Tune Up Program
The Residential HVAC Diagnostic and Tune-up program targets customers with HVAC system performance issues. There are no incentives paid directly to customers. Customers are charged a discounted, fixed-fee for the diagnosis and if needed, a similar fee for implementation of corrective actions. Thus, the program pays the portion of diagnostic and tune-up cost in excess of the customer charge below. The customer cost is as follows:

- Customer cost is $35 per unit for diagnostics test
- Customer cost is $50 per unit for tune-up

Customer Education and Public Information
These programs help customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through two processes: a mass-media campaign and an elementary- and middle-school program. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts.

Dealer Referral Network
The Dealer Referral Network assists customers in identifying qualified service providers to install energy efficiency improvements recommended and/ or subsidized by the various energy efficiency programs.

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

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Kentucky Utilities Company

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

Commercial Customer Program Participation Incentives:
The following Demand Side Management programs are available to commercial customers receiving service from the Company on the GS, AES, PS, TODS, and TODP Standard Electric Rate Schedules.

Commercial Load Management / Demand Conservation
The Commercial Load Management / Demand Conservation Program employ switches or interfaces to customer equipment, in small and large commercial businesses to help reduce the demand for electricity during peak times. The Program communicates with the switches or interface to cycle equipment. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

Commercial Conservation (Energy Audits) / Commercial Incentives
The Commercial Conservation / Commercial Inventive Program is designed to provide energy efficiency opportunities for the Companies' commercial class customers through energy audits and to increase the implementation of energy efficiency measures by providing financial incentives to assist with the replacement of aging and less efficient equipment. Incentives available to all commercial customers are based upon a $100 per kW removed for calculated efficiency improvements. A prescriptive list provides customers with incentive values for various efficiency improvements projects. Additionally, a custom rebate is available based upon company engineering validation of sustainable KW removed.

- Maximum annual incentive per facility is $50,000
- Customers can receive multi-year incentives in a single year where such multi-year incentives do not exceed the aggregate of $100,000 per facility and no incentive was provided in the immediately preceding year
- Applicable for combined Prescriptive and Custom Rebates

Commercial HVAC Diagnostics and Tune Up Program
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Kentucky Utilities Company

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

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The Dealer Referral Network assists customers in identifying qualified service providers to install energy efficiency improvements recommended and/ or subsidized by the various energy efficiency programs.

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 86.8

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

Current Program Incentive Structures

Residential Load Management / Demand Conservation

Switch Option:

- $5/month bill credit for June, July, August, & September per air conditioning unit or heat pump on single family home.
- $2/month bill credit for June, July, August, & September per electric water heater or swimming pool pump on single family home.
- If new customer registers by May 31, 2012, then a $10 gift card per air-conditioning unit, heat pump, water-heater and/or swimming pool pump switch installed.
  - Customers in a tenant landlord relationship will receive the entire $10 new customer incentive.

Multi-family Option:

- $2/month bill credit per customer for June, July, August, & September.
- $2/month incentive per air conditioning or heat pump switch to the premise owner for June, July, August, & September.
- If new customer registers by May 31, 2012, then a $10 gift card per air-conditioning unit or heat pump installed.
  - Customers in a tenant landlord relationship where the entire complex participates will split the new customer incentive with the property owner.
  - Customers in a tenant landlord relationship where only a portion of the complex participates, the tenant will receive a $5 new customer incentive.

Residential Refrigerator Removal Program

The program provides $30 per working refrigerator or freezer.

Commercial Load Management / Demand Conservation

Switch Option

- $5 per month bill credit for June, July, August, & September for air conditioning units up to 5 tons. An additional $1 per month bill credit for each additional ton of air conditioning above 5 tons based upon unit rated capacity.

Customer Equipment Interface Option

The Company will offer a Load Management / Demand Response program tailored to a commercial customer's ability to reduce load. Program participants must commit to a minimum of 50KW demand reduction per control event. The Company will continue to enroll program participants until10MW curtailable load is achieved.

- $25 per KW for verified load reduction during June, July, August, & September.
- The customer will have access to at least hourly load data for every month of the year which they remain enrolled in the program.

Date of Issue: April 30, 2012
Date Effective: May 31, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 86.8

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

Current Program Incentive Structures

Residential Load Management / Demand Conservation

Switch Option:

- $5/month bill credit for June, July, August, & September per air conditioning unit or heat pump on single family home.
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  - Customers in a tenant landlord relationship where only a portion of the complex participates, the tenant will receive a $5 new customer incentive.

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Switch Option

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- $25 per KW for verified load reduction during June, July, August, & September.
- The customer will have access to at least hourly load data for every month of the year which they remain enrolled in the program.

Date of Issue: June 29, 2012
Date Effective: May 31, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

- Additional customer charges may be incurred for metering equipment necessary for this program at costs under other tariffs.

- Additional customer charges may be incurred for metering equipment necessary for this program at costs under other tariffs.

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 86.10

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Residential Service Rate RS, Volunteer Fire Department Service Rate VFD, and Low Emission Vehicle Service Rate LEV	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00133 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00075 per kWh
DSM Incentive (DSMI)	$ 0.00006 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00049 per kWh
DSM Balance Adjustment (DBA)	$(0.00040) per kWh
Total DSMRC for Rates RS, VFD and LEV	$ 0.00223 per kWh

General Service Rate GS	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00065 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00085 per kWh
DSM Incentive (DSMI)	$ 0.00003 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00007 per kWh
DSM Balance Adjustment (DBA)	$(0.00006) per kWh
Total DSMRC for Rates GS	$ 0.00154 per kWh

All Electric School Rate AES	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00018 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00019 per kWh
DSM Incentive (DSMI)	$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per kWh
DSM Balance Adjustment (DBA)	$(0.00008) per kWh
Total DSMRC for Rate AES	$ 0.00030 per kWh

Commercial Customers Served Under Power Service Rate PS, Time of Day Secondary Service Rate TODS, and Time-of-Day Primary Service Rate TODP	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00020 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00026 per kWh
DSM Incentive (DSMI)	$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per kWh
DSM Balance Adjustment (DBA)	$ 0.00001 per kWh
Total DSMRC for Rates PS, TODS and TODP	$ 0.00048 per kWh

Industrial Customers Served Under Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Rate RTS	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00000 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00000 per kWh
DSM Incentive (DSMI)	$ 0.00000 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per kWh
DSM Balance Adjustment (DBA)	$ 0.00000 per kWh
Total DSMRC for Rates TODS, TODP, and RTS	$ 0.00000 per kWh

Date of Issue: April 30, 2012
Date Effective: April 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 86.10

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Residential Service Rate RS, Volunteer Fire Department Service Rate VFD, and Low Emission Vehicle Service Rate LEV	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00133 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00075 per kWh
DSM Incentive (DSMI)	$ 0.00006 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00049 per kWh
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Total DSMRC for Rates RS, VFD and LEV	$ 0.00223 per kWh

General Service Rate GS	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00065 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00085 per kWh
DSM Incentive (DSMI)	$ 0.00003 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00007 per kWh
DSM Balance Adjustment (DBA)	$(0.00006) per kWh
Total DSMRC for Rates GS	$ 0.00154 per kWh

All Electric School Rate AES	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00018 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00019 per kWh
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DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per kWh
DSM Balance Adjustment (DBA)	$(0.00008) per kWh
Total DSMRC for Rate AES	$ 0.00030 per kWh

Commercial Customers Served Under Power Service Rate PS, Time of Day Secondary Service Rate TODS, and Time-of-Day Primary Service Rate TODP	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00020 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00026 per kWh
DSM Incentive (DSMI)	$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per kWh
DSM Balance Adjustment (DBA)	$ 0.00001 per kWh
Total DSMRC for Rates PS, TODS, and TODP	$ 0.00048 per kWh

Industrial Customers Served Under Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Rate RTS	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00000 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00000 per kWh
DSM Incentive (DSMI)	$ 0.00000 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per kWh
DSM Balance Adjustment (DBA)	$ 0.00000 per kWh
Total DSMRC for Rates PS, TODS, TODP, and RTS	$ 0.00000 per kWh

Date of Issue: June 29, 2012
Date Effective: April 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 87
Canceling P.S.C. No. 15, Original Sheet No. 87

Adjustment Clause — ECR
Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except CTAC and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC and DSM Adjustment Clauses. Standard Electric Rate Schedules subject to this schedule are divided into Group 1 or Group 2 as follows:

Group 1: Rate Schedules RS; VFD; AES; ST.LT.; P.O.LT.; DSK; LE; TE; and Pilot Program LEV.
Group 2: Rate Schedules GS; PS; TODS; TODP; RTS; and FLS.

Prior to billings for the first billing cycle in March 2012 (cycle beginning February 29, 2012), all rate schedules noted above will be included in Group 1 for purposes of determining and applying the Environmental Surcharge Billing Factor.

RATE

The monthly billing amount under each of the schedules to which this mechanism is applicable, shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

Group Environmental Surcharge Billing Factor = Group E(m) / Group R(m)

As set forth below, Group E(m) is the sum of Jurisdictional E(m) of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the 12-month average revenue for the current expense month and for Group 2 it is the 12-month average non-fuel revenue for the current expense month.

DEFINITIONS

1) For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – BAS + BR
   a) RB is the Total Environmental Compliance Rate Base.
   b) ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the overall rate of return [cost of short-term debt, long-term debt, preferred stock, and common equity].
   c) DR is the Debt Rate [cost of short-term debt, and long-term debt].
   d) TR is the Composite Federal and State Income Tax Rate.
   e) OE is the Operating Expenses [Depreciation and Amortization Expense, Property Taxes, Emission Allowance Expense and O&M expense adjusted for the Average Month Expense already included in existing rates]. OE includes operation and maintenance expense recovery authorized by the K.P.S.C. in all approved ECR Plan proceedings.
   f) BAS is the total proceeds from by-product and allowance sales applicable to the pre-2011 Plans only.
   g) BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse applicable to the pre-2011 Plans only.
   h) Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183.

Date of Issue: December 21, 2011
Date Effective: December 16, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued By Authority of an Order of the KPSC in Case No. 2011-00161 dated December 15, 2011

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 87

Adjustment Clause — ECR
Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except CTAC and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC and DSM Adjustment Clauses. Standard Electric Rate Schedules subject to this schedule are divided into Group 1 or Group 2 as follows:

Group 1: Rate Schedules RS; VFD; AES; LS; RLS; LE; TE; and Pilot Program LEV. T
Group 2: Rate Schedules GS; PS; TODS; TODP; RTS; and FLS.

T

RATE

The monthly billing amount under each of the schedules to which this mechanism is applicable, shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

Group Environmental Surcharge Billing Factor = Group E(m) / Group R(m)

As set forth below, Group E(m) is the sum of Jurisdictional E(m) of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the 12-month average revenue for the current expense month and for Group 2 it is the 12-month average non-fuel revenue for the current expense month.

DEFINITIONS

1) For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – EAS + BR T
   a) RB is the Total Environmental Compliance Rate Base.
   b) ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the overall rate of return [cost of short-term debt, long-term debt, preferred stock, and common equity].
   c) DR is the Debt Rate [cost of short-term debt, and long-term debt].
   d) TR is the Composite Federal and State Income Tax Rate.
   e) OE is the Operating Expenses. OE includes operation and maintenance expense recovery authorized by the K.P.S.C. in all approved ECR Plan proceedings. T
   f) EAS is the total proceeds from emission allowance sales applicable to the pre-2011 Plans only. T
   g) BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse applicable to the pre-2011 Plans only.
   h) Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 87.1
Canceling P.S.C. No. 15, Original Sheet No. 87.1

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor. Jurisdictional E(m) is adjusted for any (Over)/Under collection or prior period adjustment and by the subtraction of the Revenue Collected through Base Rates for the Current Expense month to arrive at Adjusted Net Jurisdictional E(m). Adjusted Net Jurisdictional E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the 12 months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).

3) The Group 1 R(m) is the average of total Group 1 monthly base revenue for the 12 months ending with the current expense month. Base revenue includes the customer, energy, and lighting charges for each rate schedule included in Group 1 to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.

4) The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the 12 months ending with the current expense month. Base non-fuel revenue includes the customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this mechanism is applicable and automatic adjustment clause revenues for the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6.

5) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

Date of Issue: May 14, 2012
Date Effective: February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued By Authority of an Order of the KPSC in Case No. 2011-00231 dated February 29, 2012

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 87.1

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor. Jurisdictional E(m) is adjusted for any (Over)/Under collection or prior period adjustment and by the subtraction of the Revenue Collected through Base Rates for the Current Expense month to arrive at Adjusted Net Jurisdictional E(m). Adjusted Net Jurisdictional E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the 12 months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).

3) The Group 1 R(m) is the average of total Group 1 monthly base revenue for the 12 months ending with the current expense month. Base revenue includes the customer, energy, and lighting charges for each rate schedule included in Group 1 to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.

4) The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the 12 months ending with the current expense month. Base non-fuel revenue includes the customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this mechanism is applicable and automatic adjustment clause revenues for the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6.

5) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

Date of Issue: June 29, 2012
Date Effective: February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued By Authority of an Order of the KPSC in Case No. 2011-00231 dated February 29, 2012

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 90

Adjustment Clause — FF

Franchise Fee Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available as an option for collection of revenues within governmental jurisdictions which impose on Company franchise fees, permitting fees, local taxes or other charges by ordinance, franchise, or other governmental directive and not otherwise collected in the charges of Company's base rate schedules.

DEFINITIONS

Base Year - the twelve month period ending November 30.
Collection Year - the full calendar year following the Base Year.
Base Year Amount -

1) a percentage of revenues, as determined in the franchise agreement, for the Base Year; and
2) license fees, permit fees, or other costs specifically borne by Company for the purpose of maintaining the franchise as incurred in the Base Year and applicable specifically to Company by ordinance or franchise for operation and maintenance of its facilities in the franchise area, including but not limited to costs incurred by Company as a result of governmental regulation or directives requiring construction or installation of facilities beyond that normally provided by Company in accordance with applicable Rules and Regulations approved by and under the direction of the Kentucky Public Service Commission; and
3) any adjustment for over or under collection of revenues associated with the amounts in 1) or 2).

RATE

The franchise percentage will be calculated by dividing the Base Year amount by the total revenues in the Base Year for the franchise area. The franchise percentage will be monitored during the Collection Year and adjusted to recover the Base Year Amount in the Collection Year as closely as possible.

BILLING

1) The franchise charge will be applied exclusively to the base rate and all riders of bills of customers receiving service within the franchising governmental jurisdiction, before taxes.
2) The franchise charge will appear as a separate line item on the Customer's bill and show the unit of government requiring the franchise.
3) Payment of the collected franchise charges will be made to the governmental franchising body as agreed to in the franchise agreement.

TERM OF CONTRACT

As agreed to in the franchise agreement. In the event such franchise agreement should lapse but payment of franchise fees, other local taxes, or permitting fees paid by Company by ordinance, franchise, or other governmental directive should continue, collection shall continue under this tariff.

TERMS AND CONDITIONS

Service will be furnished in accordance with the provisions of the franchise agreement in so far as those provisions do not conflict with the Terms and Conditions applicable to Company approved by and under the direction of the Kentucky Public Service Commission.

Date of Issue: August 6, 2010
Date Effective: October 16, 2003
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 90

Adjustment Clause — FF

Franchise Fee Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available as an option for collection of revenues within governmental jurisdictions which impose on Company franchise fees, permitting fees, local taxes or other charges by ordinance, franchise, or other governmental directive and not otherwise collected in the charges of Company's base rate schedules.

DEFINITIONS

Base Year - the twelve month period ending November 30.
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Base Year Amount -

1) a percentage of revenues, as determined in the franchise agreement, for the Base Year; and
2) license fees, permit fees, or other costs specifically borne by Company for the purpose of maintaining the franchise as incurred in the Base Year and applicable specifically to Company by ordinance or franchise for operation and maintenance of its facilities in the franchise area, including but not limited to costs incurred by Company as a result of governmental regulation or directives requiring construction or installation of facilities beyond that normally provided by Company in accordance with applicable Rules and Regulations approved by and under the direction of the Kentucky Public Service Commission; and
3) any adjustment for over or under collection of revenues associated with the amounts in 1) or 2).

RATE

The franchise percentage will be calculated by dividing the Base Year amount by the total revenues in the Base Year for the franchise area. The franchise percentage will be monitored during the Collection Year and adjusted to recover the Base Year Amount in the Collection Year as closely as possible.

BILLING

1) The franchise charge will be applied exclusively to the base rate and all riders of bills of customers receiving service within the franchising governmental jurisdiction, before taxes.
2) The franchise charge will appear as a separate line item on the Customer's bill and show the unit of government requiring the franchise.
3) Payment of the collected franchise charges will be made to the governmental franchising body as agreed to in the franchise agreement.

TERM OF CONTRACT

As agreed to in the franchise agreement. In the event such franchise agreement should lapse but payment of franchise fees, other local taxes, or permitting fees paid by Company by ordinance, franchise, or other governmental directive should continue, collection shall continue under this tariff.

TERMS AND CONDITIONS

Service will be furnished in accordance with the provisions of the franchise agreement in so far as those provisions do not conflict with the Terms and Conditions applicable to Company approved by and under the direction of the Kentucky Public Service Commission.

Date of Issue: June 29, 2012
Date Effective: October 16, 2003
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 91

Adjustment Clause ST

School Tax

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is applied as a rate increase to all other schedules pursuant to KRS 160.617 for the recovery by the utility of school taxes in any county requiring a utility gross receipts license tax for schools under KRS 160.613.

RATE

The utility gross receipts license tax authorized under state law.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 91

Adjustment Clause ST

School Tax

APPLICABLE

In all territory served.

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Date of Issue: June 29, 2012
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 92
Canceling P.S.C. No. 15, First Revision of Original Sheet No. 92

Adjustment Clause HEA

Home Energy Assistance Program

APPLICABLE
In all territory served.

AVAILABILITY
To all residential customers.

RATE
$0.16 per meter per month.

BILLING
The HEA charge shall be shown as a separate item on customer bills.

SERVICE PERIOD
The Home Energy Assistance charge will be applied to all residential electric bills rendered during the billing cycles commencing October 1, 2007 through September 30, 2015, or as otherwise directed by the Public Service Commission. Proceeds from this charge will be used to fund residential low-income demand-side management Home Energy Assistance programs which have been designed through a collaborative advisory process and then filed with, and approved by, the Commission.

Date of Issue: December 21, 2011
Date Effective: January 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00161 dated December 15, 2011

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 92

Adjustment Clause HEA

Home Energy Assistance Program

APPLICABLE
In all territory served.

AVAILABILITY
To all residential customers.

RATE
$0.16 per meter per month.

BILLING
The HEA charge shall be shown as a separate item on customer bills.

SERVICE PERIOD
The Home Energy Assistance charge will be applied to all residential electric bills rendered during the billing cycles commencing October 1, 2007 through September 30, 2015, or as otherwise directed by the Public Service Commission. Proceeds from this charge will be used to fund residential low-income demand-side management Home Energy Assistance programs which have been designed through a collaborative advisory process and then filed with, and approved by, the Commission.

Date of Issue: June 29, 2012
Date Effective: January 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00161 dated December 15, 2011

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 95

TERMS AND CONDITIONS

Customer Bill of Rights

As a residential customer of a regulated public utility in Kentucky, you are guaranteed the following rights subject to Kentucky Revised Statutes and the provisions of the Kentucky Public Service Commission Administrative Regulations:

- You have the right to service, provided you (or a member of your household whose debt was accumulated at your address) are not indebted to the utility.
- You have the right to inspect and review the utility's rates and tariffed operating procedures during the utility's normal office hours.
- You have the right to be present at any routine utility inspection of your service conditions.
- You must be provided a separate, distinct disconnect notice alerting you to a possible disconnection of your service, if payment is not received.
- You have the right to dispute the reasons for any announced termination of your service.
- You have the right to negotiate a partial payment plan when your service is threatened by disconnection for non-payment.
- You have the right to participate in equal, budget payment plans for your natural gas and electric service.
- You have the right to maintain your utility service for up to thirty (30) days upon presentation of a medical certificate issued by a health official.
- You have the right to prompt (within 24 hours) restoration of your service when the cause for discontinuance has been corrected.
- If you have not been disconnected, you have the right to maintain your natural gas and electric service for up to thirty (30) days, provided you present a Certificate of Need issued by the Kentucky Cabinet for Human Resources between the months of November and the end of March.
- If you have been disconnected due to non-payment, you have the right to have your natural gas or electric service reconnected between the months of November through March provided you:
  1) Present a Certificate of Need issued by the Kentucky Cabinet for Human Resources, and
  2) Pay one third (1/3) of your outstanding bill ($200 maximum), and
  3) Accept referral to the Human Resources' Weatherization Program, and
  4) Agree to a repayment schedule that will cause your bill to become current by October 15.
- You have the right to contact the Public Service Commission regarding any dispute that you have been unable to resolve with your utility (call Toll Free 1-800-772-4636).

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 95

TERMS AND CONDITIONS

Customer Bill of Rights

As a residential customer of a regulated public utility in Kentucky, you are guaranteed the following rights subject to Kentucky Revised Statutes and the provisions of the Kentucky Public Service Commission Administrative Regulations:

- You have the right to service, provided you (or a member of your household whose debt was accumulated at your address) are not indebted to the utility.
- You have the right to inspect and review the utility's rates and tariffed operating procedures during the utility's normal office hours.
- You have the right to be present at any routine utility inspection of your service conditions.
- You must be provided a separate, distinct disconnect notice alerting you to a possible disconnection of your service, if payment is not received.
- You have the right to dispute the reasons for any announced termination of your service.
- You have the right to negotiate a partial payment plan when your service is threatened by disconnection for non-payment.
- You have the right to participate in equal, budget payment plans for your natural gas and electric service.
- You have the right to maintain your utility service for up to thirty (30) days upon presentation of a medical certificate issued by a health official.
- You have the right to prompt (within 24 hours) restoration of your service when the cause for discontinuance has been corrected.
- If you have not been disconnected, you have the right to maintain your natural gas and electric service for up to thirty (30) days, provided you present a Certificate of Need issued by the Kentucky Cabinet for Human Resources between the months of November and the end of March.
- If you have been disconnected due to non-payment, you have the right to have your natural gas or electric service reconnected between the months of November through March provided you:
  1) Present a Certificate of Need issued by the Kentucky Cabinet for Human Resources, and
  2) Pay one third (1/3) of your outstanding bill ($200 maximum), and
  3) Accept referral to the Human Resources' Weatherization Program, and
  4) Agree to a repayment schedule that will cause your bill to become current by October 15.
- You have the right to contact the Public Service Commission regarding any dispute that you have been unable to resolve with your utility (call Toll Free 1-800-772-4636).

Date of Issue: June 29, 2012
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 96

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS
All electric service supplied by Company shall be in accordance with the applicable rules and regulations of the Public Service Commission of Kentucky.

COMPANY TERMS AND CONDITIONS
In addition to the rules and regulations of the Commission, all electric service supplied by Company shall be in accordance with these Terms and Conditions, which shall constitute a part of all applications and contracts for service.

RATES, TERMS AND CONDITIONS ON FILE
A copy of the rate schedules, terms, and conditions under which electric service is supplied is on file with the Public Service Commission of Kentucky. A copy of such rate schedules, terms and conditions, together with the law, rules, and regulations of the Commission, is available for public inspection in each office of Company where bills may be paid.

ASSIGNMENT
No order for service, agreement or contract for service may be assigned or transferred without the written consent of Company.

RENEWAL OF CONTRACT
If, upon the expiration of any service contract for a specified term, the customer continues to use the service, the contract (unless otherwise provided therein) will be automatically renewed for successive periods of one (1) year each, subject to termination at the end of any year upon thirty (30) days prior written notice by either party.

AGENTS CANNOT MODIFY AGREEMENT WITHOUT CONSENT OF P.S.C. OF KY.
No agent has power to amend, modify, alter, or waive any of these Terms and Conditions, or to bind Company by making any promises or representations not contained herein.

SUPERSEDE PREVIOUS TERMS AND CONDITIONS
These Terms and Conditions supersede all terms and conditions under which Company has previously supplied electric service.

Date of Issue: August 6, 2010
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 96

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TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

A written application or contract, properly executed, may be required before Company is obligated to render electric service. Company shall have the right to reject for valid reasons any such application or contract.

All applications for service shall be made in the legal name of the party desiring the service.

Where an unusual expenditure for construction or equipment is necessary or where the proposed manner of using electric service is clearly outside the scope of Company's standard rate schedules, Company may establish special contracts giving effect to such unusual circumstances. Customer accepts that non-standard service may result in the delay of required maintenance or, in the case of outages, restoration of service.

TRANSFER OF APPLICATION

Applications for electric service are not transferable and new occupants of premises will be required to make application for service before commencing the use of electricity. Customers who have been receiving electric service shall notify Company when discontinuance of service is desired, and shall pay for all electric service furnished until such notice has been given and final meter readings made by Company.

CONTRACTED DEMANDS

For rate applications where billing demand minimums are determined by the Contract Demand customer shall execute written Contract prior to rendering of service. At Company's sole discretion, in lieu of a written contract, a completed load data sheet or other written load specification, as provided by Customer, can be used to determine the maximum load on Company's system for determining Contract Demand minimum.

OPTIONAL RATES

If two or more rate schedules are available for the same class of service, it is Customer's responsibility to determine the options available and to designate the schedule under which customer desires to receive service.

Company will, at any time, upon request, advise any customer as to the most advantageous rate for existing or anticipated service requirements as defined by the customer, but Company does not assume responsibility for the selection of such rate or for the continuance of the lowest annual cost under the rate selected.

In those cases in which the most favorable rate is difficult to predetermine, Customer will be given the opportunity to change to another schedule, unless otherwise prevented by the rate schedule under which Customer is currently served, after trial of the schedule originally designated; however, after the first such change, Company shall not be required to make a change in schedule more often than once in twelve (12) months.

TERMS AND CONDITIONS

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TERMS AND CONDITIONS

Customer Responsibilities

From time to time, Customer should investigate Customer's operating conditions to determine a desirable change from one available rate to another. Company, lacking knowledge of changes that may occur at any time in Customer's operating conditions, does not assume responsibility that Customer will at all times be served under the most beneficial rate.

In no event will Company make refunds covering the difference between the charges under the rate in effect and those under any other rate applicable to the same class of service.

CUSTOMER'S EQUIPMENT AND INSTALLATION

Customer shall furnish, install, and maintain at Customer's expense all electrical apparatus and wiring to connect with Company's service drop or service line. All such apparatus and wiring shall be installed and maintained in conformity with applicable statutes, laws or ordinances and with the rules and regulations of the constituted authorities having jurisdiction. Customer shall not install wiring or connect and use any motor or other electricity-using device which in the opinion of Company is detrimental to its electric system or to the service of other customers of Company. Company assumes no responsibility whatsoever for the condition of Customer's electrical wiring, apparatus, or appliances, nor for the maintenance or removal of any portion thereof.

In the event Customer builds or extends its own transmission or distribution system over property Customer owns, controls, or has rights to, and said system extends or may extend into the service territory of another utility company, Customer will notify Company of their intention in advance of the commencement of construction.

OWNER'S CONSENT TO OCCUPY

Customer shall grant easements and rights-of-way on and across Customer's property at no cost to Company.

ACCESS TO PREMISES AND EQUIPMENT

Company shall have the right of access to Customer's premises at all reasonable times for the purpose of installing, meter reading, inspecting, repairing, or removing its equipment used in connection with its supply of electric service or for the purpose of turning on and shutting off the supply of electricity when necessary and for all other proper purposes. Customer shall not construct or permit the construction of any structure or device which will restrict the access of Company to its equipment for any of the above purposes.

PROTECTION OF COMPANY'S PROPERTY

Customers will be held responsible for tampering, interfering with, breaking of seals of meters, or other equipment of Company installed on Customer's premises, and will be held liable for same according to law. Customer hereby agrees that no one except the employees of Company shall be allowed to make any internal or external adjustments of any meter or any other piece of apparatus which shall be the property of Company.

TERMS AND CONDITIONS

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Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 97.2

TERMS AND CONDITIONS

Customer Responsibilities

POWER FACTOR

Company installs facilities to supply power to Customer at or near unity power factor.

Company expects any customer to use apparatus which shall result in a power factor near unity. However, Company will permit the use of apparatus which shall result, during normal operation, in a power factor not lower than 90 percent either lagging or leading.

Where Customer's power factor is less than 90 percent, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable corrective equipment to maintain a power factor of 90 percent or higher.

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

Except in cases where Customer has a contract with Company for reserve or auxiliary service, no other electric light or power service will be used by Customer on the same installation in conjunction with Company's service, either by means of a throw-over switch or any other connection.

LIABILITY

Customer assumes all responsibility for the electric service upon Customer's premises at and from the point of delivery of electricity and for the wires and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of electricity, occasioned by such electricity or said wires and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence of Company.

NOTICE TO COMPANY OF CHANGES IN CUSTOMER'S LOAD

The service connections, transformers, meters, and appurtenances supplied by Company for the rendition of electric service to its customers have a definite capacity which may not be exceeded without damage. In the event that Customer contemplates any material increase in Customer's connected load, whether in a single increment or over an extended period, Customer shall immediately give Company written notice of this fact so as to enable it to enlarge the capacity of such equipment. In case of failure to give such notice Customer may be held liable for any damage done to meters, transformers, or other equipment of Company caused by such material increase in Customer's connected load. Should Customer make a permanent change in the operation of electrical equipment that materially reduces the maximum load required by Customer, Company may reduce Customer's contract capacity.

PERMITS

Customer shall obtain or cause to be obtained all permits, easements, or certificates, except street permits, necessary to give Company or its agents access to Customer's premises and equipment and to enable its service to be connected therewith. In case Customer is not the owner of the premises or of intervening property between the premises and Company's distribution lines the customer shall obtain from the proper owner or owners the necessary

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Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 97.2

TERMS AND CONDITIONS

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Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

TERMS AND CONDITIONS

Customer Responsibilities

PERMITS (continued)

consent to the installation and maintenance in said premises and in or about such intervening property of all such wiring or other customer-owned electrical equipment as may be necessary or convenient for the supply of electric service to customer. Provided, however, to the extent permits, easements, or certificates are necessary for the installation and maintenance of Company-owned facilities, Company shall obtain the aforementioned consent.

The construction of electric facilities to provide service to a number of customers in a manner consistent with good engineering practice and the least public inconvenience sometimes requires that certain wires, guys, poles, or other appurtenances on a customer's premises be used to supply service to neighboring customers. Accordingly, each customer taking Company's electric service shall grant to Company such rights on or across his or her premises as may be necessary to furnish service to neighboring premises, such rights to be exercised by Company in a reasonable manner and with due regard for the convenience of Customer.

Company shall make or cause to be made application for any necessary street permits, and shall not be required to supply service under Customer's application until a reasonable time after such permits are granted.

TERMS AND CONDITIONS

Customer Responsibilities

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Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 98

TERMS AND CONDITIONS

Company Responsibilities

METERING

The electricity used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

POINT OF DELIVERY OF ELECTRICITY

The point of delivery of electrical energy supplied by Company shall be at the point, as designated by Company, where Company's facilities are connected with the facilities of Customer, irrespective of the location of the meter.

EXTENSION OF SERVICE

The main transmission lines of Company, or branches thereof, will be extended to such points as provide sufficient load to justify such extensions or in lieu of sufficient load, Company may require such definite and written guarantees from a customer, or group of customers, in addition to any minimum payments required by the Tariff as may be necessary. This requirement may also be made covering the repayment, within a reasonable time, of the cost of tapping such existing lines for light or power service or both.

COMPANY'S EQUIPMENT AND INSTALLATION

Company will furnish, install, and maintain at its expense the necessary overhead service drop or service line required to deliver electricity at the voltage contracted for, to Customer's electric facilities.

Company will furnish, install, and maintain at its expense the necessary meter or meters. (The term meter as used here and elsewhere in these rules and regulations shall be considered to include all associated instruments and devices, such as current and potential transformers installed for the purpose of measuring deliveries of electricity to the customer.) Suitable provision for Company's meter, including an adequate protective enclosure for the same if required, shall be made by Customer. Title to the meter shall remain in Company, with the right to install, operate, maintain, and remove same. Customer shall protect such property of Company from loss or damage, and no one who is not an agent of Company shall be permitted to remove, damage, or tamper with the same. Customer shall execute such reasonable form of easement agreement as may be required by Company.

Notwithstanding the provisions of 807 KAR 5:006, Section 13(4), a reasonable time shall be allowed subsequent to Customer's service application to enable Company to construct or install the facilities required for such service. In order that Company may make suitable provision for enlargement, extension or alteration of its facilities, each applicant for commercial or industrial service shall furnish Company with realistic estimates of prospective electricity requirements.

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Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 98

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TERMS AND CONDITIONS

Company Responsibilities

COMPANY NOT LIABLE FOR INTERRUPTIONS

Company will exercise reasonable care and diligence in an endeavor to supply service continuously and without interruption but does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay or failure of electric service not caused by the willful negligence of Company, or resulting from any cause or circumstance beyond the reasonable control of Company.

COMPANY NOT LIABLE FOR DAMAGE ON CUSTOMER'S PREMISES

Company is merely a supplier of electricity delivered to the point of connection of Company's and Customer's facilities, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or property of Customer or of third persons resulting from the presence, use or abuse of electricity on Customer's premises or resulting from defects in or accidents to any of Customer's wiring, equipment, apparatus, or appliances, or resulting from any cause whatsoever other than the negligence of Company

LIABILITY

In no event shall Company have any liability to Customer or any other party affected by the electrical service to Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to Customer or any other party. In the event that the customer's use of Company's service causes damage to Company's property or injuries to persons, Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

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FIRM SERVICE T

Where a customer-generator supplies all or part of the customer-generator's own load and desires Company to provide supplemental or standby service for that load, the customer-generator must contract for such service under Company's Supplemental or Standby Service Rider, otherwise Company has no obligation to supply the non-firm service. This requirement does not apply to Net Metering Service (Rider NMS).

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Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 99

TERMS AND CONDITIONS
Character of Service

Electric service, under the rate schedules herein, will be 60 cycle, alternating current delivered from Company's various load centers and distribution lines at typical nominal voltages and phases, as available in a given location, as follows:

SECONDARY VOLTAGES
Residential Service -
Single phase 120/240 volts three-wire service or 120/208Y volts three-wire service where network system is available.
Non-Residential Service -
1) Single phase 120/240 volts three-wire service, or 120/208Y volts three-wire service where network system is available.
2) Three phase 240 volts three-wire service, 120/240 volts four-wire service, 480 volts three-wire service, 120-208Y volts four-wire service, or 277/480Y four-wire service.

PRIMARY VOLTAGES
According to location, 2,400/4160Y volts, 7,200/12,470Y volts, or 34,500 volts

TRANSMISSION VOLTAGES
According to location, 69,000 volts, 138,000 volts, or 345,000 volts.

The voltage available to any individual customer shall depend upon the voltage of Company's lines serving the area in which Customer's electric load is located.

RESTRICTIONS
1. Except for minor loads, with approval of company, two-wire service is restricted to those customers on service July 1, 2004.
2. To be eligible for the rate applicable to any delivery voltage other than secondary voltage, Customer must furnish and maintain complete substation structure, transformers, and other equipment necessary to take service at the primary or transmission voltage available at point of connection.
   a) In the event Company is required to provide transformation to reduce an available voltage to a lower voltage for delivery to a customer, Customer shall be served at the rate applicable to the lower voltage; provided, however, that if the same rate is applicable to both the available voltage and the delivery voltage, Customer may be required to make a non-refundable payment to reflect the additional investment required to provide service.
   b) The available voltage shall be the voltage on that distribution or transmission line which Company designates as being suitable from the standpoint of capacity and other operating characteristics for supplying the requirements of Customer.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 99

TERMS AND CONDITIONS

Character of Service

Electric service, under the rate schedules herein, will be 60 cycle, alternating current delivered from Company's various load centers and distribution lines at typical nominal voltages and phases, as available in a given location, as follows:

SECONDARY VOLTAGES
Residential Service -
Single phase 120/240 volts three-wire service or 120/208Y volts three-wire service where network system is available.
Non-Residential Service -
1) Single phase 120/240 volts three-wire service, or 120/208Y volts three-wire service where network system is available.
2) Three phase 240 volts three-wire service, 120/240 volts four-wire service, 480 volts three-wire service, 120-208Y volts four-wire service, or 277/480Y four-wire service.

PRIMARY VOLTAGES
According to location, 2,400/4160Y volts, 7,200/12,470Y volts, or 34,500 volts

TRANSMISSION VOLTAGES
According to location, 69,000 volts, 138,000 volts, or 345,000 volts.

The voltage available to any individual customer shall depend upon the voltage of Company's lines serving the area in which Customer's electric load is located.

RESTRICTIONS
1. Except for minor loads, with approval of company, two-wire service is restricted to those customers on service July 1, 2004.
2. To be eligible for the rate applicable to any delivery voltage other than secondary voltage, Customer must furnish and maintain complete substation structure, transformers, and other equipment necessary to take service at the primary or transmission voltage available at point of connection.
   a) In the event Company is required to provide transformation to reduce an available voltage to a lower voltage for delivery to a customer, Customer shall be served at the rate applicable to the lower voltage; provided, however, that if the same rate is applicable to both the available voltage and the delivery voltage, Customer may be required to make a non-refundable payment to reflect the additional investment required to provide service.
   b) The available voltage shall be the voltage on that distribution or transmission line which Company designates as being suitable from the standpoint of capacity and other operating characteristics for supplying the requirements of Customer.

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Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 100

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

Residential electric service is available for uses customarily associated with residential occupation, including lighting, cooking, heating, cooling, refrigeration, household appliances, and other domestic purposes.

1. Residential rates are based on service to single family units and are not applicable to multi-family dwellings served through a single meter. Where two or more families occupy a residential building, Company will require, as a condition precedent to the application of the residential rate, that the wiring in the building be so arranged as to permit each family to be served through a separate meter. In those cases where such segregation of wiring would involve undue expense to Customer, Company will allow service to two or more families to be taken through one meter, but in this event the minimum bills of the applicable residential rate shall be multiplied by the number of families thus served, such number of families to be determined on the basis of the number of kitchens in the building. At Customer's option, in lieu of the foregoing, electric service rendered to a multi-family residential building through a single meter will be classified as commercial and billed on the basis of service to one customer at an appropriate non-residential rate.

2. Single family unit service shall include usage of electric energy customarily incidental to home occupations, such as the office of a physician, surgeon, dentist, musician or artist when such occupation is carried on by Customer in his residence.

3. A residential building used by a single family as a home, which is also used to accommodate roomers or boarders for compensation, will be billed at the residential rate provided it does not exceed twelve (12) rooms in size. Such a residential building of more than twelve (12) rooms used to accommodate roomers or borders for compensation will be classified as commercial and billed on the appropriate rate. In determining the room rating of rooming and boarding houses, all wired rooms shall be counted except hallways, vestibules, alcoves, closets, bathrooms, lavatories, garrets, attics, storage rooms, trunk rooms, basements, cellars, porches and private garages.

4. Service used in residential buildings occupied by fraternity or sorority organizations associated with educational institutions will be classified as residential and billed at the residential rate.

5. Where both residential and general or commercial classes of service are supplied through a single meter, such combined service shall be billed at the appropriate non-residential rate. Customer may arrange his wiring so as to separate the general service from the residential service, in which event two meters will be installed by Company and separate residential and general service rates applied to the respective classes of service.

6. If Customer's barns, pump house or other outbuildings are located at such distance from his residence as to make it impracticable to supply service thereto through his residential meter, the separate meter required to measure service to such remotely located buildings will be considered a separate service contract and billed as a separate customer on the applicable non-residential rate.

Date of Issue: August 6, 2010
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 100

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

Residential electric service is available for uses customarily associated with residential occupation, including lighting, cooking, heating, cooling, refrigeration, household appliances, and other domestic purposes.

1. Residential rates are based on service to single family units and are not applicable to multi-family dwellings served through a single meter. Where two or more families occupy a residential building, Company will require, as a condition precedent to the application of the residential rate, that the wiring in the building be so arranged as to permit each family to be served through a separate meter. In those cases where such segregation of wiring would involve undue expense to Customer, Company will allow service to two or more families to be taken through one meter, but in this event the minimum bills of the applicable residential rate shall be multiplied by the number of families thus served, such number of families to be determined on the basis of the number of kitchens in the building. At Customer's option, in lieu of the foregoing, electric service rendered to a multi-family residential building through a single meter will be classified as commercial and billed on the basis of service to one customer at an appropriate non-residential rate.

2. Single family unit service shall include usage of electric energy customarily incidental to home occupations, such as the office of a physician, surgeon, dentist, musician or artist when such occupation is carried on by Customer in his residence.

3. A residential building used by a single family as a home, which is also used to accommodate roomers or boarders for compensation, will be billed at the residential rate provided it does not exceed twelve (12) rooms in size. Such a residential building of more than twelve (12) rooms used to accommodate roomers or borders for compensation will be classified as commercial and billed on the appropriate rate. In determining the room rating of rooming and boarding houses, all wired rooms shall be counted except hallways, vestibules, alcoves, closets, bathrooms, lavatories, garrets, attics, storage rooms, trunk rooms, basements, cellars, porches and private garages.

4. Service used in residential buildings occupied by fraternity or sorority organizations associated with educational institutions will be classified as residential and billed at the residential rate.

5. Where both residential and general or commercial classes of service are supplied through a single meter, such combined service shall be billed at the appropriate non-residential rate. Customer may arrange his wiring so as to separate the general service from the residential service, in which event two meters will be installed by Company and separate residential and general service rates applied to the respective classes of service.

6. If Customer's barns, pump house or other outbuildings are located at such distance from his residence as to make it impracticable to supply service thereto through his residential meter, the separate meter required to measure service to such remotely located buildings will be considered a separate service contract and billed as a separate customer on the applicable non-residential rate.

Date of Issue: June 29, 2012
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 100.1

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

7. Single-phase power service used for domestic purposes will be permitted under Residential Rate RS when measured through the residential meter subject to the conditions set forth below:

   (a) Single-phase motors may be served at 120 volts if the locked-rotor current at rated voltage does not exceed 50 amperes. Motors with locked-rotor current ratings in excess of 50 amperes must be served at 240 volts.

   (b) Single-phase motors of new central residential cooling installations with total locked-rotor ratings of not to exceed 125 amperes (inclusive of any auxiliary motors arranged for simultaneous starting with the compressor) may be connected for across-the-line starting provided the available capacity of Company's electric distribution facilities at desired point of supply is such that, in Company's judgment, the starting of such motors will not result in excessive voltage dips and undue disturbance of lighting service and television reception of nearby electric customers. However, except with Company's express written consent, no new single-phase central residential cooling unit having a total lock-rotor rating in excess of 125 amperes inclusive of auxiliary motors arranged for simultaneous starting with the compressor) shall hereafter be connected to Company's lines, or be eligible for electric service therefrom, unless it is equipped with an approved type of current-limiting device for starting which will reduce the initial and incremental starting current inrush to a maximum of 100 amperes per step. Company shall be furnished with reasonable advance notice of any proposed central residential cooling installation.

   (c) In the case of multi-motored devices arranged for sequential starting of the motors, the above rules are considered to apply to the locked-rotor currents of the individual motors; if arranged for simultaneous starting of the motors, the rules apply to the sum of the locked-rotor currents of all motors so started.

   (d) Any motor or motors served through a separate meter will be billed as a separate customer.

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Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 100.1

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

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   (a) Single-phase motors may be served at 120 volts if the locked-rotor current at rated voltage does not exceed 50 amperes. Motors with locked-rotor current ratings in excess of 50 amperes must be served at 240 volts.

   (b) Single-phase motors of new central residential cooling installations with total locked-rotor ratings of not to exceed 125 amperes (inclusive of any auxiliary motors arranged for simultaneous starting with the compressor) may be connected for across-the-line starting provided the available capacity of Company's electric distribution facilities at desired point of supply is such that, in Company's judgment, the starting of such motors will not result in excessive voltage dips and undue disturbance of lighting service and television reception of nearby electric customers. However, except with Company's express written consent, no new single-phase central residential cooling unit having a total lock-rotor rating in excess of 125 amperes inclusive of auxiliary motors arranged for simultaneous starting with the compressor) shall hereafter be connected to Company's lines, or be eligible for electric service therefrom, unless it is equipped with an approved type of current-limiting device for starting which will reduce the initial and incremental starting current inrush to a maximum of 100 amperes per step. Company shall be furnished with reasonable advance notice of any proposed central residential cooling installation.

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Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 101

TERMS AND CONDITIONS

Billing

METER READINGS AND BILLS

Each bill for utility service shall be issued in compliance with 807 KAR 5:006, Section 6.

All bills will be based upon meter readings made in accordance with Company's meter reading schedule. Company, except if prevented by reasons beyond its control, shall read customers meters at least quarterly, except that customer-read meters shall be read at least once during the calendar year.

In the case of opening and closing bills when the total period between regular and special meter readings is less than thirty days, the minimum charges of the applicable rate schedules will be prorated on the basis of the ratio of the actual number of days in such period to thirty days.

When Company is unable to read Customer's meter after reasonable effort, or when Company experiences circumstances which make actual meter readings impossible or impracticable, Customer may be billed on an estimated basis and the billing will be adjusted as necessary when the meter is read.

In the event Company's meter fails to register properly by reason of damage, accident, etc., Company shall have the right to estimate Customer's consumption during the period of failure on the basis of such factors as Customer's connected load, heating degree days, and consumption during a previous corresponding period and during a test period immediately following replacement of the defective meter.

Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within twelve (12) calendar days from date of rendition thereof. If full payment is not received within three (3) calendar days after the due date of the bill, a late payment charge will be assessed on the current month's charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice. There will be no adverse credit impact on the customer's payment and credit record, including credit scoring, both internally and externally, and the account will not be considered delinquent for any purpose if the Company receives the customer's payment within fifteen days after the date on which the Company issues the customer's bill.

Failure to receive a bill does not exempt Customer from these provisions of Company's Terms and Conditions.

READING OF SEPARATE METERS NOT COMBINED

For billing purposes, each meter upon Customer's premises will be considered separately and readings of two (2) or more meters will not be combined except where Company's operating convenience requires the installation of two (2) or more meters upon Customer's premises instead of one (1) meter.

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Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 101

TERMS AND CONDITIONS

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Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

TERMS AND CONDITIONS

Billing

CLASSIFICATION OF CUSTOMERS

For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are primarily engaged in a process or processes which create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32 and 33. All other non-residential customers will be defined as "commercial."

MONITORING OF CUSTOMER USAGE

In order to detect unusual deviations in individual customer consumption, Company will monitor the usage of each customer at least once annually. In addition, Company may investigate usage deviations brought to its attention as a result of its ongoing meter reading or billing processor customer inquiry. Should an unusual deviation in Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of Customer's meter reading and billing records, Company may contact Customer to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether it shows an average error greater than two (2) percent fast or slow. Company will notify Customer of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 10(4) and (5).

RESALE OF ELECTRIC ENERGY

Electric energy furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such energy to any other person, firm, or corporation on the Customer's premises, or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company's billing.

MINIMUM CHARGE

Without limiting the foregoing, the Demand Charge shall be due regardless of any event or occurrence that might limit (a) Customer's ability or interest in operating Customer's facility, including, but without limitation, any acts of God, fires, floods, earthquakes, acts of government, terrorism, severe weather, riot, embargo, changes in law, or strikes or (b) Company's ability to serve customer.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

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TERMS AND CONDITIONS

BILLING

CUSTOMER RATE ASSIGNMENT T

If Customer takes service under a rate schedule the eligibility for which contains a minimum or maximum demand parameter (or both), Company will review Customer's demand and usage data at least once annually to determine the rate schedule under which Customer will take service until the next review and rate determination. Company will also conduct such a review and determination upon Customer's request. Company shall not be obligated to change Customer's rate determination based upon detection of a substantial deviation of Customer's demand or usage if, after consultation with Customer, Company determines in its sole discretion that such deviation is not indicative of Customer's likely long-term demand. Similarly, Company may assign Customer to a rate schedule for which Customer would not be eligible based solely on Customer's historical demand or usage, but Company may do so only as part of a review and rate determination that involves consulting with Customer about Customer's likely future demand, as well as Customer's special contract demand, if applicable.

Any such review and rate determination shall be deemed conclusively to be the correct rate determination for Customer for all purposes and for all periods until Company conducts the next such review and determination for Customer. Therefore, Company shall not be liable for any refunds to Customer based upon Customer's rate assignment, and Company shall not seek to back-bill Customer based upon Customer's rate assignment, for any periods between and including such reviews and determinations unless, and only in the event that, a particular review and rate determination are shown to have been materially erroneous at the time they were conducted, in which case Company may be liable for a refund, or may back-bill Customer, only for the period from the erroneous review and determination to the present or the next non-erroneous review and determination, whichever is shorter.

If Company determines during a review as described above that Customer is eligible to take service under more than one rate schedule and that Customer is then taking service under such a rate schedule, Company will not change Customer's rate assignment; it will remain Customer's responsibility to choose between optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1.

If Company determines during a review as described above that Customer is eligible to take service under more than one rate schedule and that Customer is not then taking service under such a rate schedule, Company will (1) provide reasonable notice to Customer of the options available and (2) assign Customer to the rate schedule Company reasonably believes will be most financially beneficial to Customer based on Customer's historical demand and usage, which assignment Company will change upon Customer's request to take service under another rate schedule for which Customer is eligible. Company shall have no refund obligation or bear any other liability or responsibility for its initial assignment of Customer to a rate for which Customer is eligible; it is at all times Customer's responsibility to choose between optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

The Billing section of the current KU Terms and Conditions is contained on four pages instead of the current two pages.

TERMS AND CONDITIONS

BILLING

Nothing in this section is intended to curtail or diminish Customer's responsibility to choose among optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1. Likewise, except as explicitly stated in the paragraph above, nothing in this section creates an obligation or responsibility for Company to assign Customer to a particular rate schedule for which Customer is eligible if Customer is eligible for more than one rate schedule. T

CUSTOMER RATE MIGRATION

A change from one rate to another will be effective with the first full billing period following a customer's request for such change, or with a rate change mandated by changes in a customer's load. In cases where a change from one rate to another necessitates a change in metering, the change from one rate to another will be effective with the first full billing period following the meter change.

CLASSIFICATION OF CUSTOMERS

For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are primarily engaged in a process or processes which create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32 and 33. All other non-residential customers will be defined as "commercial."

MONITORING OF CUSTOMER USAGE

In order to detect unusual deviations in individual customer consumption, Company will monitor the usage of each customer at least once annually. In addition, Company may investigate usage deviations brought to its attention as a result of its ongoing meter reading or billing processor customer inquiry. Should an unusual deviation in Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of Customer's meter reading and billing records, Company may contact Customer to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether it shows an average error greater than two (2) percent fast or slow. Company will notify Customer of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 10(4) and (5).

RESALE OF ELECTRIC ENERGY

Electric energy furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such energy to any other person, firm, or corporation on the Customer's premises, or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company's billing.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

The Billing section of the current KU Terms and Conditions is contained on four pages instead of the current two pages.

TERMS AND CONDITIONS

BILLING

MINIMUM CHARGE

Without limiting the foregoing, the Demand Charge shall be due regardless of any event or occurrence that might limit (a) Customer's ability or interest in operating Customer's facility, including, but without limitation, any acts of God, fires, floods, earthquakes, acts of government, terrorism, severe weather, riot, embargo, changes in law, or strikes or (b) Company's ability to serve customer. T

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 102

TERMS AND CONDITIONS

Deposits

GENERAL

1) Company may require a cash deposit or other guaranty from customers to secure payment of bills in accordance with 807 KAR 5:006, Section 7, except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection.
2) Deposits may be required from all customers not meeting satisfactory credit and payment criteria. Satisfactory credit for customers will be determined by utilizing independent credit sources (primarily utilized with new customers having no prior history with Company), as well as historic and ongoing payment and credit history with Company.
   a) Examples of independent credit scoring resources include credit scoring services, public record financial information, financial scoring and modeling services, and information provided by independent credit/financial watch services.
   b) Satisfactory payment criteria with Company may be established by paying all bills rendered, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments, having no meter diversion or theft of service.
3) Company may offer residential or general service customers the option of paying all or a portion of their deposits in installments over a period not to exceed the first four (4) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.

RESIDENTIAL

1) Residential customers are those customers served under Residential Service, Sheet No. 5.
2) The deposit for a residential customer is in the amount of $135.00, which is calculated in accordance with 807 KAR 5:006, Section 7(1)(b).
3) Company will retain Customer's deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.
4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise become a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 102

TERMS AND CONDITIONS

Deposits

GENERAL

1) Company may require a cash deposit or other guaranty from customers to secure payment of bills in accordance with 807 KAR 5:006, Section 7, except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection.
2) Deposits may be required from all customers not meeting satisfactory credit and payment criteria. Satisfactory credit for customers will be determined by utilizing independent credit sources (primarily utilized with new customers having no prior history with Company), as well as historic and ongoing payment and credit history with Company.
   a) Examples of independent credit scoring resources include credit scoring services, public record financial information, financial scoring and modeling services, and information provided by independent credit/financial watch services.
   b) Satisfactory payment criteria with Company may be established by paying all bills rendered, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments, having no meter diversion or theft of service.
3) Company may offer residential or general service customers the option of paying all or a portion of their deposits in installments over a period not to exceed the first four (4) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.

RESIDENTIAL

1) Residential customers are those customers served under Residential Service, Sheet No. 5.
2) The deposit for a residential customer is in the amount of $135.00, which is calculated in accordance with 807 KAR 5:006, Section 7(1)(b).
3) Company will retain Customer's deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.
4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise become a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

Date of Issue: June 29, 2012
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

TERMS AND CONDITIONS

Deposits

GENERAL SERVICE

1) General service customers are those customers served under General Service, Sheet No. 10.
2) The deposit for a general service customer is in the amount of $220.00, which is calculated in accordance with 807 KAR 5:006, Section 7(1)(b).
3) Company shall retain Customer's deposit as long as Customer remains on service.
4) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten (10%) percent, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential or general service, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR 5:006, Section 7(1)(a).
2) For customers not meeting the parameters of GENERAL SERVICE ¶ 2, above, Company may retain Customer's deposit as long as Customer remains on service.
3) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten (10%) percent, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise become a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

TERMS AND CONDITIONS

Deposits

GENERAL SERVICE

1) General service customers are those customers served under General Service, Sheet No. 10.
2) The deposit for a general service customer is in the amount of $220.00, which is calculated in accordance with 807 KAR 5:006, Section 7(1)(b). The deposit for a General Service customer may be waived when the General Service delivery is to a detached building used in conjunction with a Residential Service and the General Service usage is no more than 300 kWh per month. T T T T
3) Company shall retain Customer's deposit as long as Customer remains on service.
4) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten (10%) percent, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential or general service, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR 5:006, Section 7(1)(a).
2) For customers not meeting the parameters of GENERAL SERVICE ¶ 2, above, Company may retain Customer's deposit as long as Customer remains on service.
3) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten (10%) percent, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise become a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to any residential customer or general service customer. Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in this plan at any time.

The budgeted amount will be determined by Company and will be based on one-twelfth of Customer's usage for either an actual or estimated twelve (12) months. The budgeted amount will be subject to review and adjustment by Company at any time during Customer's budget year. If actual usage indicates Customer's account will not be current with the final payment in Customer's budget year, Customer will be required to pay their Budget Payment Plan account to $0 prior to the beginning of the customer's next budget year.

If a customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove the customer from the plan, restore the customer to regular billing, and require immediate payment of any deficiency. A customer removed from the Budget Payment Plan for non-payment may be prohibited from further participation in the plan for twelve (12) months.

Failure to receive a bill in no way exempts a customer from the provisions of these terms and conditions.

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to any residential customer or general service customer. Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in this plan at any time.

The budgeted amount will be determined by Company and will be based on one-twelfth of Customer's usage for either an actual or estimated twelve (12) months. The budgeted amount will be subject to review and adjustment by Company at any time during Customer's budget year. If actual usage indicates Customer's account will not be current with the final payment in Customer's budget year, Customer will be required to pay their Budget Payment Plan account to $0 prior to the beginning of the customer's next budget year.

If a customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove the customer from the plan, restore the customer to regular billing, and require immediate payment of any deficiency. A customer removed from the Budget Payment Plan for non-payment may be prohibited from further participation in the plan for twelve (12) months.

Failure to receive a bill in no way exempts a customer from the provisions of these terms and conditions.

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 104
Canceling P.S.C. No. 15, Original Sheet No. 104

TERMS AND CONDITIONS
Bill Format

KU
a PPL company

Customer Service: 1-800-981-0600 (M-F, 7 a.m. to 7 p.m. ET)
Telephone Payments: 1-800-981-0600; press 1-2-2-3 (24 hours a day; $2.95 fee)
Walk-in Center: Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service: www.lge-ku.com (24 hours a day)

DUE DATE	Pay This Amount
11/28/11	$104.52

Current due date applies to the current bill only. Previous amount due may be subject to disconnection.

ACCOUNT INFORMATION

Account Number:	3000-1111-2222
Account Name:	JOHN DOE
Service Address:	1234 Main St RICHMOND KY
Next Read Will Occur:	12/13/11 - 12/15/11
Date Bill Mailed:	11/14/11 (Meter Read Portion 11)

Averages for Billing Period	This Year	Last Year
Average Temperature	51°	54°
Number of Days Billed	28	28
Electric/kwh per day	38.3	39.7

BILLING SUMMARY

Previous Balance		270.69
Payment(s) Received 10/20 - 11/14		-241.19
Balance as of 11/14		29.50
Current Electric Charges	87.21	
Current Taxes and Fees	2.61	
Current Charges as of 11/14		89.82
Other Charges (See Other Charges Box)		-14.80
Total Amount Due		104.52

ELECTRIC CHARGES

Rate Type: Residential Service – All Electric

Basic Service Charge	8.50
Energy Charge ($0.06719 x 1074.00 kwh)	72.16
Other Charges For Above Rates	
Fuel Adjustment ($0.00163 x 1074 kwh)	1.75
Electric DSM ($0.00188 x 1074.00 kwh)	2.02
Environmental Surcharge (3.120% x $84.43)	2.63
Home Energy Assistance Fund Charge	0.15
Total Electric Charges	$87.21

Meter Reading Information

Meter # C326958	
Actual Reading on 11/11/11	92676
Previous Reading on 10/14/11	91602
Current kwh Usage	1074
Meter Multiplier	1
Metered kwh Usage	1074

Please see reverse side for additional charges.

Customer Service 1-800-981-0600

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number	Payment Due Date	Pay This Amount	Pay This Amount 3 Days After Due Date	Winter Help Donation	Amount Enclosed
3000-1111-2222	11/28/11	$104.52	$109.01	$	$

☐ Check here if plan(s) requested on back of stub

OFFICE USE ONLY: BF
MRU1091170, G000000
P23.07
PF:Y eB:P

KU
PO BOX 9001954
LOUISVILLE, KY 40290-1954

#131900062 48
JOHN DOE
1234 MAIN ST
RICHMOND KY 40475-8750

Service Address: 1234 Main St

020000000000000000000000124560000001189500000000000000

Date of Issue: December 22, 2011
Date Effective: December 22, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 104

TERMS AND CONDITIONS

T

Bill Format

KU
a PPL company

Customer Service: 1-800-331-7370 (M-F, 7a.m.to 7 p.m ET)
Telephone Payments: 1-800-331-7370; press 1-2-2-3 (24 hours a day; $2.95 fee)
Walk-in Center Hours: Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service: www.lge-ku.com (24 hours a day)

DATE DUE	AMOUNT DUE
04/23/12	$65.85

Late Payment Fees will be applied to current charges if the current amount due is not received in full by the payment due date on this bill even if payment arrangements have been made. Please have your account number available when calling to discuss your account.

ACCOUNT INFORMATION

Account Number:	3000-0216-5900
Account Name:	JOHN DOE
Service Address:	1234 ANYWHERE ST
Next Read Will Occur:	05/03/12 - 05/07/12
Date Bill Mailed:	04/04/12 (Meter Read Portion 04)

BILLING SUMMARY

Previous Balance		12.26
Payments as of 3/6 - 4/3		(12.26)
Balance as of 4/3		0.00
Electric Charges	62.13	
Taxes and Fees	3.72	
Utility Charges as of 4/3		65.85
Total Amount Due		65.85

Averages for Billing Period	This Year	Last Year
Average Temperature	60 °	48 °
Number of Days Billed	29	30
Electric/kwh per Day	24.7	28.3

ELECTRIC CHARGES

Rate Type: Residential Service

Basic Service Charge	8.50
Energy Charge ($0.06987 x 717.00 kwh)	50.10
Electric DSM ($0.00223 x 717.00 kwh)	1.60
Fuel Adjustment ($.00054 x 717 kwh)	0.39
Environmental Surcharge (2.280% x $60.59)	1.38
Home Energy Assistance Fund Charge	0.16
Total Electric Charges	$62.13

Meter Reading Information

Meter# #12345	
Actual Reading on 4/3/12	6938
Previous Reading on 3/5/12	6221
Current kwh Usage	717
Meter Multiplier	1
Metered kwh Usage	717

TAXES AND FEES

Rate Increase For School Tax (3.00% x $61.97)	1.86
Franchise Fee-Lexington (3.00% x $61.97)	1.86
Total Taxes and Fees	$3.72

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date $3.29

Please see reverse side for additional charges. Bring entire bill when paying in person.

Customer Service (800) 981-0600

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number	Payment Due Date	Amount Due by Due Date	Amount Due 3 Days After Due Date	Winter Care Donation	Amount Enclosed
3000-0216-5900	04/23/12	$65.85	$69.14	$	$

☐ Check here if plan(s) requested on back of stub.

OFFICE USE ONLY:
MRU1081170, G000000
P23.07
PF:Y eB:P

KU
PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900062 48
JOHN DOE
1234 Anywhere St
Lexington, KY KY 40026-3745

Service Address: 1234 Anywhere St

020000000000000000000000124560000001189500000000000000

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 104.1
Canceling P.S.C. No. 15, Original Sheet No. 104.1

TERMS AND CONDITIONS
Bill Format

Account Number 3000-1111-2222 Page 2

OTHER CHARGES

Reconnect Charges	25.00
Removal from Installment Plan	101.25
Late Payment Charge	-6.05
Security Deposit	-135.00
Total Other Charges Due	-$14.80

TAXES AND FEES

Rate Increase For School Tax (3.000% x $87.06)	2.61
Total Taxes and Fees	2.61

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date $4.49

Environmental Surcharge: A monthly charge or credit passed on to customers to pay for the cost of pollution-control equipment needed to meet government-mandated air emission reduction requirements.

Franchise Fee: A pass-through of fees paid by the Company to municipalities for the right to serve customers located in those municipalities

IMPORTANT INFORMATION

The power to save. It's in your hands. The amount of electricity you consumed during this billing cycle resulted in the production of approximately 2,148 pounds of CO2 (carbon). A typical residential customer uses 1,000 kilowatt hours of electricity per month, which would result in the production of 2,000 lbs. of carbon. Visit our Web site at www.lge-ku.com for Smart Saver tips designed to help you better manage and lessen the environmental impact of your engery usage.

For a copy of your rate schedule, visit www.lge-ku.com or call our Customer Service Department.

New enrollment only - Please check box(es) below and on front of stub.

☐ Budget Plan

☐ I would like to enroll in Demand Conservation

☐ Auto Pay (voided check must be provided). Please note that any past due balance on your KU account will be debited from your bank account immediately upon enrollment in the Auto Pay program. To avoid unintended debits to your bank account, please make sure your KU account balance is current before enrolling in Auto Pay.

Please deduct my Auto Pay Payment from my Checking Account.
I hereby authorize KU to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future KU accounts, and will remain in effect until revoked by me or KU.

Signature: ______________________

Date: ______________________

Processing Auto Pay requests can take up to two billing cycles. Please continue making regular payments until you receive a bill that indicates the amount due will be deducted from your bank account on the payment due date.

Date of Issue: December 22, 2011
Date Effective: December 22, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 104.1

TERMS AND CONDITIONS

Bill Format

T

Account Number 3000-0216-5900 Page 2

IMPORTANT INFORMATION

The power to save. It's in your hands. The amount of electricity you consumed during this billing cycle resulted in the production of approximately 1,434 pounds of CO2 (carbon). A typical residential customer uses 1,000 kilowatt hours of electricity per month, which would result in the production of 2,000 lbs. of carbon. Visit our Web site at www.lge-ku.com for Smart Saver tips designed to help you better manage and lessen the environmental impact of your engery usage.

For a copy of your rate schedule, visit www.lge-ku.com or call our Customer Service Department.

If you use mail to submit your payment, please update your records to reflect the new address (located on the front of the bill) stub) for our payment processing center. Remember, you can pay your bill on line when you sign in or register your account at my.lge-ku.com.

New enrollment only - Please check box(es) below and on front of stub.

☐ Budget Plan

☐ I would like to enroll in Demand Conservation

☐ Auto Pay (voided check must be provided). *Please note that any past due balance on your LG&E account will be debited from your bank account immediately upon enrollment in the Auto Pay program. To avoid unintended debits to your bank account, please make sure your LG&E account balance is current before enrolling in Auto Pay.*

Please deduct my Auto Pay Payment from my Checking Account.
I hereby authorize KU to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future KU accounts, and will remain in effect until revoked by me or KU.

Signature: ______________________

Date: ______________________

Processing Auto Pay requests can take up to two billing cycles. Please continue making regular payments until you receive a bill that indicates the amount due will be deducted from your bank account on the payment due date.

Signature: ______________________

Date: ______________________

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 105

TERMS AND CONDITIONS

Discontinuance of Service

In accordance with and subject to the rules and regulations of the Public Service Commission of Kentucky, Company shall have the right to refuse or discontinue service to an applicant or customer under the following conditions:

A. When Company's or Commission's rules and regulations have not been complied with. However, service may be discontinued or refused only after Company has made a reasonable effort to induce Customer to comply with its rules and then only after Customer has been given at least ten (10) days written notice of such intention, mailed to his last known address.

B. When a dangerous condition is found to exist on Customer's or applicant's premises. In such case service will be discontinued without notice or refused, as the case might be. Company will notify Customer or applicant immediately of the reason for the discontinuance or refusal and the corrective action to be taken before service can be restored or initiated.

C. When Customer or applicant refuses or neglects to provide reasonable access and/or easements to and on his premises for the purposes of installation, operation, meter reading, maintenance, or removal of Company's property. Customer shall be given fifteen (15) days written notice of Company's intention to discontinue or refuse service.

D. When Applicant is indebted to Company for service furnished. Company may refuse to serve until indebtedness is paid.

E. When Customer or Applicant does not comply with state, municipal or other codes, rules and regulations applying to such service.

F. When directed to do so by governmental authority.

G. Service will not be supplied to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same or any other premises until payment of such indebtedness shall have been made. Service will not be continued to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same premises in accordance with 807 KAR 5:006, Section 14(1)(f). Unpaid balances of previously rendered Final Bills may be transferred to any account for which Customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred Final Bills will be subject to Company's collections and disconnect procedures in accordance with 807 KAR 5:006, Section 14(1)(f). Final Bills transferred following a lapse in service will not be subject to disconnection unless: (1) such service was provided pursuant to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement which allows for such a disconnection; or (3) the current account is subsequently disconnected for service supplied at that point of delivery, at which time, all unpaid and past due balances must be paid prior to reconnect. Company shall have the right to transfer Final Bills between residential and commercial with residential characteristics (e.g., service supplying common use facilities of any apartment building) revenue classifications.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 105

TERMS AND CONDITIONS

Discontinuance of Service

In accordance with and subject to the rules and regulations of the Public Service Commission of Kentucky, Company shall have the right to refuse or discontinue service to an applicant or customer under the following conditions:

A. When Company's or Commission's rules and regulations have not been complied with. However, service may be discontinued or refused only after Company has made a reasonable effort to induce Customer to comply with its rules and then only after Customer has been given at least ten (10) days written notice of such intention, mailed to his last known address.

B. When a dangerous condition is found to exist on Customer's or applicant's premises. In such case service will be discontinued without notice or refused, as the case might be. Company will notify Customer or applicant immediately of the reason for the discontinuance or refusal and the corrective action to be taken before service can be restored or initiated.

C. When Customer or applicant refuses or neglects to provide reasonable access and/or easements to and on his premises for the purposes of installation, operation, meter reading, maintenance, or removal of Company's property. Customer shall be given fifteen (15) days written notice of Company's intention to discontinue or refuse service.

D. When Applicant is indebted to Company for service furnished. Company may refuse to serve until indebtedness is paid.

E. When Customer or Applicant does not comply with state, municipal or other codes, rules and regulations applying to such service.

F. When directed to do so by governmental authority.

G. Service will not be supplied to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same or any other premises until payment of such indebtedness shall have been made. Service will not be continued to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same premises in accordance with 807 KAR 5:006, Section 14(1)(f). Unpaid balances of previously rendered Final Bills may be transferred to any account for which Customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred Final Bills will be subject to Company's collections and disconnect procedures in accordance with 807 KAR 5:006, Section 14(1)(f). Final Bills transferred following a lapse in service will not be subject to disconnection unless: (1) such service was provided pursuant to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement which allows for such a disconnection; or (3) the current account is subsequently disconnected for service supplied at that point of delivery, at which time, all unpaid and past due balances must be paid prior to reconnect. Company shall have the right to transfer Final Bills between residential and commercial with residential characteristics (e.g., service supplying common use facilities of any apartment building) revenue classifications.

Date of Issue: June 29, 2012
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

TERMS AND CONDITIONS

Discontinuance of Service

Service will not be supplied or continued to any premises if at the time of application for service Applicant is merely acting as an agent of a person or former customer who is indebted to Company for service previously supplied at the same or other premises until payment of such indebtedness shall have been made. Service will not be supplied where Applicant is a partnership or corporation whose general partner or controlling stockholder is a present or former customer who is indebted to Company for service previously supplied at the same premises until payment of such indebtedness shall have been made.

H. For non-payment of bills. Company shall have the right to discontinue service for non-payment of bills after Customer has been given at least ten days written notice separate from his original bill. Cut-off may be effected not less than twenty-seven (27) days after the mailing date of original bills unless, prior to discontinuance, a residential customer presents to Company a written certificate, signed by a physician, registered nurse, or public health officer, that such discontinuance will aggravate an existing illness or infirmity on the affected premises, in which case discontinuance may be effected not less than thirty (30) days from the original date of discontinuance. Company shall notify Customer, in writing, of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance.

I. For fraudulent or illegal use of service. When Company discovers evidence that by fraudulent or illegal means Customer has obtained unauthorized service or has diverted the service for unauthorized use or has obtained service without same being properly measured, the service to Customer may be discontinued without notice. Within twenty-four (24) hours after such termination, Company shall send written notification to Customer of the reasons for such discontinuance of service and of Customer's right to challenge the termination by filing a formal complaint with the Public Service Commission of Kentucky. Company's right of termination is separate from and in addition to any other legal remedies which the utility may pursue for illegal use or theft of service. Company shall not be required to restore service until Customer has complied with all rules of Company and regulations of the Commission and Company has been reimbursed for the estimated amount of the service rendered and the cost to Company incurred by reason of the fraudulent use.

When service has been discontinued for any of the above reasons, Company shall not be responsible for any damage that may result therefrom.

Discontinuance or refusal of service shall be in addition to, and not in lieu of, any other rights or remedies available to Company.

Company may defer written notice based on Customer's payment history provided Company continues to provide the required ten (10) days written notice prior to discontinuance of service.

TERMS AND CONDITIONS

Discontinuance of Service

Service will not be supplied or continued to any premises if at the time of application for service Applicant is merely acting as an agent of a person or former customer who is indebted to Company for service previously supplied at the same or other premises until payment of such indebtedness shall have been made. Service will not be supplied where Applicant is a partnership or corporation whose general partner or controlling stockholder is a present or former customer who is indebted to Company for service previously supplied at the same premises until payment of such indebtedness shall have been made.

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Discontinuance or refusal of service shall be in addition to, and not in lieu of, any other rights or remedies available to Company.

Company may defer written notice based on Customer's payment history provided Company continues to provide the required ten (10) days written notice prior to discontinuance of service.

TERMS AND CONDITIONS

Line Extension Plan

A. AVAILABILITY
In all territory served by where Company does not have existing facilities to meet Customer's electric service needs.

B. DEFINITIONS
1) "Company" shall mean Kentucky Utilities Company.
2) "Customer" shall mean the applicant for service. When more than one electric service is requested by an applicant on the same extension, such request shall be considered one customer under this plan when the additional service request(s) is only for incidental or minor convenience loads or when the applicant for service is the developer of a subdivision.
3) "Line Extension" shall mean the single phase facilities required to serve Customer by the shortest route most convenient to Company from the nearest existing adequate Company facilities to Customer's delivery point, approved by Company, and excluding transformers, service drop, and meters, if required and normally provided to like customers.
4) "Permanent Service" shall mean service contracted for under the terms of the applicable rate schedule but not less than one year and where the intended use is not seasonal, intermittent, or speculative in nature.
5) "Commission" shall mean the Public Service Commission of Kentucky.

C. GENERAL
1) All extensions of service will be made through the use of overhead facilities except as provided in these rules.
2) Customer requesting service which requires an extension(s) shall furnish to Company, at no cost, properly executed easement(s) for right-of-way across Customer's property to be served.
3) Customer requesting extension of service into a subdivision, subject to the jurisdiction of a public commission, board, committee, or other agency with authority to zone or otherwise regulate land use in the area and require a plat (or Plan) of the subdivision, Customer shall furnish, at no cost, Company with the plat (or plan) showing street and lot locations with utility easement and required restrictions. Plats (or plans) supplied shall have received final approval of the regulating body and recorded in the office of the appropriate County Court Clerk when required. Should no regulating body exist for the area into which service is to be extended, Customer shall furnish Company the required easement.
4) The title to all extensions, rights-of way, permits, and easements shall be and remain with Company.
5) Where Company is required or elects to construct an additional extension or lateral to serve Customer or another customer, Company reserves the right to connect to any extension constructed under this plan and Customer shall grant to Company, at no cost, properly executed easement(s) for right-of-way across Customer's property for the additional extension or lateral.
6) Customer must agree in writing to take service when the extension is completed and have his building or other permanent facility wired and ready for connection.
7) Nothing herein shall be construed as preventing Company from making electric line extensions under more favorable terms than herein prescribed provided the potential revenue is of such amount and permanency as to warrant such terms and render economically

TERMS AND CONDITIONS

Line Extension Plan

A. AVAILABILITY
In all territory served by where Company does not have existing facilities to meet Customer's electric service needs.

B. DEFINITIONS
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Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 106.1

TERMS AND CONDITIONS
Line Extension Plan

C. GENERAL (continued)
feasible the capital expenditure involved and provided such extensions are made to other customers under similar conditions.
8) Company may require a non-refundable deposit in cases where Customer does not have a real need or in cases where the estimated revenue does not justify the investment.
9) Company shall not be obligated to extend its lines in cases where such extensions, in the good judgment of Company, would be unfeasible, impractical, or contrary to good engineering or operating practice, unless otherwise ordered by Commission.

D. NORMAL LINE EXTENSIONS
1) In accordance with 807 KAR 5:041, Section 11(1), Company will provide, at no cost, a line extension of up to 1,000 feet to Customer requesting permanent service where the installed transformer capacity does not exceed 25 kVA.
2) Where Customer requires poly-phase service or transformer capacity in excess of 25 kVA and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ 1 above.

E. OTHER LINE EXTENSIONS
1) In accordance with 807 KAR 5:041, Section 11(2), Company shall provide to Customer requesting permanent service a line extension in excess of 1,000 feet per customer but Company may require the total cost of the footage in excess of 1,000 feet per customer, based on the average cost per foot of the total extension, be deposited with Company by Customer.
2) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension for each additional customer connected during that year directly to the original extension for which the deposit was made.
3) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension less the length of the lateral or extension for each additional customer connected during that year by a lateral or extension to the original extension for which the deposit was made.
4) No refund shall be made for additional customers connected to an extension or lateral from the original extension for which the deposit was made.
5) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten (10) year refund period ends.
6) Where Customer requires poly-phase service or transformer capacity above 25 kVA per customer and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in OTHER LINE EXTENSIONS ¶ 1 above.

F. OVERHEAD LINE EXTENSIONS TO SUBDIVISIONS
1) In accordance with 807 KAR 5:041, Section 11(3), Customer desiring service extended for and through a subdivision may be required by Company to deposit the total cost of the extension.
2) Each year for ten (10) years Company shall refund to Customer, the cost of 1,000 feet of extension for each additional customer connected during that year directly to the original extension for which the deposit was made.
3) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten-year refund period ends.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 106.1

TERMS AND CONDITIONS

Line Extension Plan

C. GENERAL (continued)
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3) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten-year refund period ends.

Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 106.2

TERMS AND CONDITIONS

Line Extension Plan

G. MOBILE HOME LINE EXTENSIONS

1) Company will make line extensions for service to mobile homes in accordance with 807 KAR 5:041, Section 12, and Commission's Order, dated August 9, 1991, in Case No. 91-213,
2) Company shall provide, at no cost, a line extension of up to 300 feet to Customer requesting permanent service for a mobile home.
3) Company shall provide to Customer requesting permanent service for a mobile home a line extension in excess of 300 feet and up to 1,000 feet but Company may require the total cost of the footage in excess of 300 feet, based on the average cost per foot of the total extension, be deposited with Company by Customer. Beyond 1,000 feet, the policies set forth in OTHER LINE EXTENSIONS shall apply.
4) Each year for four (4) years Company shall refund to Customer equal amounts of the deposit for the extension from 300 feet to 1,000 feet.
5) If service is disconnected for sixty (60) days, if the original mobile home is removed and not replaced by another mobile home or a permanent structure in sixty (60) days, the remainder of the deposit is forfeited.
6) No refund will be made except to the original customer.

H. UNDERGROUND LINE EXTENSIONS

General

1) Company will make underground line extensions for service to new residential customers and subdivisions in accordance with 807 KAR 5:041, Section 21.
2) In order that Company may make timely provision for materials, and supplies, Company may require Customer to execute a contract for an underground extension under these Terms and Conditions with Company at least six (6) months prior to the anticipated date service is needed and Company may require Customer to deposit with Company at least 10% of any amounts due under the contract at the time of execution. Customer shall deposit the balance of any amounts due under the contract with Company prior to ordering materials or commencement of actual construction by Company of facilities covered by the contract.
3) Customer shall give Company at least 120 days written notice prior to the anticipated date service is needed and Company will undertake to complete installation of its facilities at least thirty (30) days prior to that date. However, nothing herein shall be interpreted to require Company to extend service to portions of subdivisions not under active development.
4) At Company's discretion, Customer may perform a work contribution to Company's specifications, including but not limited to conduit, setting pads, or any required trenching and backfilling, and Company shall credit amounts due from Customer for underground service by Company's estimated cost for such work contribution.
5) Customer will provide, own, operate and maintain all electric facilities on his side of the point of delivery with the exception of Company's meter.
6) In consideration of Customer's underground service, Company shall credit any amounts due under the contract for each service at the rate of $50.00 or Company's average estimated installed cost for an overhead service whichever is greater.
7) Unit charges, where specified herein, are determined from Company's estimate of Company's average unit cost of such construction and the estimated cost differential between underground and overhead distribution systems in representative residential subdivisions.

Date of Issue: August 6, 2010
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 106.2

TERMS AND CONDITIONS

Line Extension Plan

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Date of Issue: June 29, 2012
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 15, Second Revision of Original Sheet No. 106.3
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TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS
General (continued)

8) Three phase primary required to supply either individual loads or the local distribution system may be overhead unless Customer chooses underground construction and deposits with Company a non-refundable deposit for the cost differential.

Individual Premises

Where Customer requests and Company agrees to supply underground service to an individual premise, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.

Medium Density Subdivisions

1) A medium density residential subdivision is defined as containing ten or more lots for the construction of new residential buildings each designed for less than five (5)-family occupancy.

2) Customer shall provide any required trenching and backfilling or at Company's discretion be required to deposit with Company a non-refundable amount determined by a unit charge of $8.93 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.

3) The Customer may be required to advance to the Company the Company's full estimated cost of construction of an underground electric distribution extension. Where Customer is required to provide trenching and backfilling, advance will be the Company's full estimate cost of construction. Where Customer is required to deposit with the Company a non-refundable advance in place of trenching and backfilling, advance will be determined by a unit charge of $20.61 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.

4) Each year for ten (10) years Company shall refund to Customer an amount determined as follows:
   a. Where customer is required to provide trenching and backfilling, a refund of $5,000 for each customer connected during that year.
   b. Where customer is required to provide a non-refundable advance, 500 times the difference in the unit charge advance amount in 3) and the non-refundable unit charge advance in 2) for each customer connected during that year

5) In no case shall the refunds provided for herein exceed the amounts deposited less any non-refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends.

Date of Issue: November 22, 2011
Date Effective: With Bills Rendered On and After December 30, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 106.3

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS
General (continued)

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Date of Issue: June 29, 2012
Date Effective: With Bills Rendered On and After December 30, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, Original Sheet No. 106.4

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS (continued)

High Density Subdivisions

1) A high density residential subdivision is defined as building complexes consisting of two or more buildings each not more than three stories above grade and each designed for five (5) or more family occupancy.
2) Customer shall provide any required trenching and backfilling or at Company's discretion be required to deposit with Company a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.
3) The Customer may be required to advance to the Company the Company's full estimated cost of construction of an underground electric distribution extension.
   i. Company shall refund to Customer any amounts due when permanent service is provided by Company to twenty (20%) percent of the family units in Customer's project.
   ii. In no case shall the refunds provided for herein exceed the amounts deposited less any non refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends.

Other Underground Subdivisions

In cases where a particular residential subdivision does not meet the conditions provided for above, Customer requests and Company agrees to supply underground service, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.

I. SPECIAL CASES

1) Where Customer requests service that is seasonal, intermittent, speculative in nature, at voltages of 34.5kV or greater, or where the facilities requested by Customer do not meet the Terms and Conditions outlined in previous sections of LINE EXTENSION PLAN and the anticipated revenues do not justify Company's installing facilities required to meet customers needs, Company may request that Customer deposit with Company a refundable amount to justify Company's investment.
2) Each year for ten (10) years Company shall refund to Customer, an amount calculated by:
   a. Adding the sum of Customer's annual base rate monthly electric demand billing for that year to the sum of the annual base rate monthly electric billing of the monthly electric demand billing for that year of any customer(s), who connects directly to the facilities provided for in this agreement and requiring no further investment by Company
   b. times the refundable amount divided by the estimated total ten-year base rate electric demand billing required to justify the investment.
3) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten-year refund period ends.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 106.4

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS (continued)

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Date of Issue: June 29, 2012
Date Effective: August 1, 2012, subject to Article I.1.1 of the Settlement Agreement attached to and approved in September 30, 2010 KPSC Order in Case No. 2010-00204
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PURPOSE

To provide procedures for reducing the consumption of electric energy on the Kentucky Utilities Company (Company) system in the event of a capacity shortage and to restore service following an outage. Notwithstanding any provisions of these Energy Curtailment and Service Restoration Procedures, the Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that the Company believes necessary, in whatever order consistent with good utility practices and not on an unduly discriminatory basis, to preserve system integrity and to prevent the collapse of the Company's electric system or interconnected electric network or to restore service following an outage. Such actions will be taken giving priority to maintaining service to the Company's retail and full requirements customers relative to other sales whenever feasible and as allowed by law.

ENERGY CURTAILMENT PROCEDURE

PRIORITY LEVELS

For the purpose of these procedures, the following Priority Levels have been established:

I. Essential Health and Safety Uses – to be given special consideration in these procedures shall, insofar as the situation permits, include the following types of use

A. "Hospitals", which shall be limited to institutions providing medical care to patients.

B. "Life Support Equipment", which shall be limited to kidney machines, respirators, and similar equipment used to sustain the life of a person.

C. "Police Stations and Government Detention Institutions", which shall be limited to essential uses required for police activities and the operation of facilities used for the detention of persons.

D. "Fire Stations", which shall be limited to facilities housing mobile fire-fighting apparatus.

E. "Communication Services", which shall be limited to essential uses required for telephone, telegraph, television, radio and newspaper operations, and operation of state and local emergency services.

F. "Water and Sewage Services", which shall be limited to essential uses required for the supply of water to a community, flood pumping and sewage disposal.

G. "Transportation and Defense-related Services", which shall be limited to essential uses required for the operation, guidance control and navigation of air, rail and mass transit systems, including those uses essential to the national defense and operation of state and local emergency services. These uses shall include essential street, highway and signal-lighting services.

Kentucky Utilities Company

TERMS AND CONDITIONS

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TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

Although, when practical, these types of uses will be given special consideration when implementing the manual load-shedding provisions of this program, any customer may be affected by rotating or unplanned outages and should install emergency generation equipment if continuity of service is essential. Where the emergency is system-wide in nature, consideration will be given to the use of rotating outages as operationally practicable. In case of customers supplied from two utility sources, only one source will be given special consideration. Also, any other customers who, in their opinion, have critical equipment should install emergency generation equipment.

Company maintains lists of customers with life support equipment and other critical needs for the purpose of curtailments and service restorations. Company, lacking knowledge of changes that may occur at any time in customer's equipment, operation, and backup resources, does not assume the responsibility of identifying customers with priority needs. It shall, therefore, be the customer's responsibility to notify Company if Customer has critical needs.

II. Critical Commercial and Industrial Uses -- Except as described in Section III below, these uses shall include commercial or industrial operations requiring regimented shutdowns to prevent conditions hazardous to the general population, and to energy utilities and their support facilities critical to the production, transportation, and distribution of service to the general population. Company shall maintain a list of such customers for the purpose of curtailments and service restoration.

III. Residential Use -- The priority of residential use during certain weather conditions (for example severe winter weather) will receive precedence over critical commercial and industrial uses. The availability of Company service personnel and the circumstances associated with the outage will also be considered in the restoration of service.

IV. Non-critical commercial and industrial uses.

V. Nonessential Uses -- The following and similar types of uses of electric energy shall be considered nonessential for all customers:

A. Outdoor flood and advertising lighting, except for the minimum level to protect life and property, and a single illuminated sign identifying commercial facilities when operating after dark.

B. General interior lighting levels greater than minimum functional levels.

C. Show-window and display lighting.

D. Parking-lot lighting above minimum functional levels.

E. Energy use to lower the temperature below 78 degrees during operation of cooling equipment and above 65 degrees during operation of heating equipment.

F. Elevator and escalator use in excess of the minimum necessary for non-peak hours of use.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

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Date of Issue: June 29, 2012
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

G. Energy use greater than that which is the minimum required for lighting, heating, or cooling of commercial or industrial facilities for maintenance cleaning or business-related activities during non-business hours.

Non-jurisdictional customers will be treated in a manner consistent with the curtailment procedures contained in the service agreement between the parties or the applicable tariff.

CURTAILMENT PROCEDURES

In the event Company's load exceeds internal generation, transmission, or distribution capacity, or other system disturbances exist, and internal efforts have failed to alleviate the problem, including emergency energy purchases, the following steps may be taken, individually or in combination, in the order necessary as time permits:

1. Customers having their own internal generation capacity will be curtailed, and customers on curtailable contracts will be curtailed for the maximum hours and load allowable under their contract. Nothing in this procedure shall limit Company's rights under the Curtailable Service Rider tariff.
2. Power output will be maximized at Company's generating units.
3. Company use of energy at its generating stations will be reduced to a minimum.
4. Company's use of electric energy in the operation of its offices and other facilities will be reduced to a minimum.
5. The Kentucky Public Service Commission will be advised of the situation.
6. An appeal will be made to customers through the news media and/or personal contact to voluntarily curtail as much load as possible. The appeal will emphasize the defined priority levels as set forth above.
7. Customers will be advised through the use of the news media and personal contact that load interruption is imminent.
8. Implement procedures for interruption of selected distribution circuits.

SERVICE RESTORATION PROCEDURES

Where practical, priority uses will be considered in restoring service and service will be restored in the order I through IV as defined under PRIORITY LEVELS. However, because of the varieties of unpredictable circumstances which may exist or precipitate outages, it may be necessary to balance specific individual needs with infrastructure needs that affect a larger population. When practical, Company will attempt to provide estimates of repair times to aid customers in assessing the need for alternative power sources and temporary relocations.

Date of Issue: August 6, 2010
Date Effective: January 8, 2007
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

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Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(1)(a)9
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

A statement that customer notice has been given in compliance with subsections (3) and (4) of this section with a copy of the notice.

Response:

Customer notice has been given in compliance with 807 KAR 5:001 Section 10(3) and (4). See attached Certificate of Notice.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	))))	**CASE NO. 2012-00221**

CERTIFICATE OF NOTICE

Pursuant to the Kentucky Public Service Commission's Regulation 807 KAR 5:001, Section 10(1)(a)(9), I hereby certify that I am Lonnie E. Bellar, Vice President, State Regulation and Rates, for Kentucky Utilities Company ("KU" or "Company"), a utility furnishing retail electric service within the Commonwealth of Kentucky which, on the 29th day of June, 2012, filed an application with the Kentucky Public Service Commission for the approval of an adjustment of the electric rates, terms, and conditions of KU, and that notice to the public of the filing of the application has been completed in all respects as required by 807 KAR 5:001, Section 10(3) and (4) and 807 KAR 5:011, Sections 8(2)(c) and 9(2), as follows:

On the 29th day of June, 2012, the notice to the public was delivered for exhibition and public inspection at the offices and places of business of the Company in the territory affected thereby, to-wit, at the following places:

Barlow
Campbellsville
Carrollton
Danville
Earlington
Eddyville
Elizabethtown
Georgetown
Greenville
Harlan
Lexington
London
Maysville
Middlesboro
Morehead
Morganfield
Mt. Sterling
Paris
Richmond
Shelbyville
Somerset
Versailles
Winchester

and that the same will be kept open to public inspection at said offices and places of business in conformity with the requirements of 807 KAR 5:001, Section 10(4)(f) and 807 KAR 5:011, Section 8(2).

I further certify that more than twenty (20) customers will be affected by said change by way of an increase in their rates or charges, and that on the 8th day of June, 2012, there was delivered to the Kentucky Press Association, an agency that acts on behalf of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, for publication therein once a week for three consecutive weeks beginning on June 22, 2012, a notice of the filing of KU's application, including its proposed rates, a copy of said notice being attached hereto, and a list of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, a copy of said list being attached hereto. A certificate of publication of said notice will be furnished to the Kentucky Public Service Commission upon completion of same pursuant to 807 KAR 5:001, Section 10(4)(d).

In addition, beginning on June 29, 2012, KU began including a general statement explaining the Application in this case with the bills for all Kentucky retail customers during the course of their regular monthly billing cycle.

Also beginning on June 29, 2012, KU posted on its Internet website a complete copy of KU's application in this case. Both the notice being published in newspapers and the bill inserts being sent to customers include the web address to the online posting.

Given under my hand this 29th day of June, 2012.

Lonnie E. Bellar
Vice President, State Regulation and Rates
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of June, 2012.

(SEAL)
Notary Public

My Commission Expires:
July 21, 2015

NOTICE

Notice is hereby given that Kentucky Utilities Company seeks approval by the Public Service Commission, Frankfort, Kentucky of an adjustment of electric rates and charges proposed to become effective on and after August 1, 2012, subject to the "Stay-Out" Commitment in Article I.1.1 of the Settlement Agreement approved in September 30, 2010 Public Service Commission Order in Case No. 2010-00204, under which the change in rates may be filed with the Public Service Commission during 2012, but not take effect before January 1, 2013.

KU CURRENT AND PROPOSED ELECTRIC RATES

Residential Service - Rate RS

	Current	Proposed
Basic Service Charge per Month:	$8.50	$13.00
Energy Charge per kWh:	$0.06987	$0.07235

Volunteer Fire Department Service - Rate VFD

	Current	Proposed
Basic Service Charge per Month:	$8.50	$13.00
Energy Charge per kWh:	$0.06987	$0.07235

General Service - Rate GS

	Current	Proposed
Basic Service Charge per Meter Per Month:		
Single-Phase	$17.50	$20.00
Three-Phase	$32.50	$35.00
Energy Charge per kWh:	$0.08332	$0.08678

Availability of Service: Text changes clarify that demand component of eligibility for taking service under this rate will be calculated on 12-month average of monthly maximum loads. Also clarifies that a customer taking service under this rate schedule who ceases to take service hereunder must meet eligibility requirements of new customer to again take service under this rate schedule.

Determination of Maximum Load: New provision states how maximum load will be measured.

All Electric School - Rate AES

	Current	Proposed
Basic Service Charge per Meter Per Month:		
Single-Phase	$17.50	$20.00
Three-Phase	$32.50	$35.00
Energy Charge per kwh:	$0.06670	$0.07060

Availability of Service: Text change clarifies that customer taking service under this rate schedule who later ceases to take such service may not again take service under this rate schedule because it is closed.

Power Service – Rate PS

Secondary Service	Current	Proposed
Basic Service Charge (per Month)	$90.00	$90.00
Energy Charge (per kWh)	$ 0.03300	$ 0.03349
Demand Charge (per kW per month of billing demand)		
Summer Rate (May through September)	$13.90	$14.40
Winter Rate (All Other Months)	$11.65	$12.10

Primary Service	Current	Proposed
Basic Service Charge (per Month)	$90.00	$125.00
Energy Charge (per kWh)	$ 0.03300	$ 0.03349
Demand Charge (per kW per month of billing demand)		
Summer Rate (May through September)	$13.72	$ 14.75
Winter Rate (All Other Months)	$11.45	$ 12.73

Availability of Service: Text changes clarify that demand component of eligibility for taking service under this rate will be calculated on 12-month average of monthly maximum loads. Also clarifies that a customer taking service under this rate schedule who ceases to take service hereunder must meet eligibility requirements of new customer to again take service under this rate schedule.

Time-of-Day Secondary Service Rate TODS

	Current	Proposed
Basic Service Charge (per Month)	$200.00	$200.00
Energy Charge (per kWh)	$ 0.03490	$ 0.03590
Maximum Load Charge (per kW per month)		
Peak Demand Period	$ 3.89	$ 4.50
Intermediate Demand Period	$ 2.43	$ 2.80
Base Demand Period	$ 3.05	$ 3.50

Availability of Service: Text changes clarify that demand component of eligibility for taking service under this rate will be calculated on 12-month average of monthly maximum loads.

Time-of-Day Primary Service Rate TODP

	Current	Proposed
Basic Service Charge (per Month)	$300.00	$300.00
Energy Charge (per kWh)	$ 0.03522	$ 0.03557
Maximum Load Charge (per kVA per month)		
Peak Demand Period	$ 3.67	$ 4.30
Intermediate Demand Period	$ 2.31	$ 2.70
Base Demand Period	$ 1.28	$ 1.60

Availability of Service: Text changes clarify that demand component of eligibility for taking service under this rate will be calculated on 12-month average of monthly maximum loads.

Retail Transmission Service Rate RTS

	Current	Proposed

Basic Service Charge (per Month)	$500.00	$750.00
Energy Charge (per kWh)	$ 0.03414	$ 0.03408
Maximum Load Charge (per kVA per month)		
Peak Demand Period	$ 3.54	$ 3.90
Intermediate Demand Period	$ 2.30	$ 2.90
Base Demand Period	$ 0.85	$ 1.30

Availability of Service: Text changes clarify that demand component of eligibility for taking service under this rate will be calculated on 12-month average of monthly maximum loads.

Fluctuating Load Service – Rate FLS

Primary Service	**Current**	**Proposed**
Basic Service Charge (per Month)	$500.00	$750.00
Energy Charge (per kWh)	$ 0.03419	$ 0.03419
Maximum Load Charge (per kVA per month)		
Peak Demand Period	$ 2.30	$ 2.40
Intermediate Demand Period	$ 1.41	$ 1.44
Base Demand Period	$ 1.57	$ 1.75

Transmission Service	**Current**	**Proposed**
Basic Service Charge (per Month)	$500.00	$750.00
Energy Charge (per kWh)	$ 0.02947	$ 0.03092
Maximum Load Charge (per kVA per month)		
Peak Demand Period	$ 2.30	$ 2.40
Intermediate Demand Period	$ 1.41	$ 1.44
Base Demand Period	$ 0.82	$ 1.00

Current:

Where:

1) the monthly billing demand for the Primary Peak and Intermediate Demand Periods is the greater of:
   a) the maximum measured load in the current billing period, or
   b) a minimum of 60% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

   the monthly billing demand for the Primary Base Demand Period is the greater of:
   a) the maximum measured load in the current billing period but not less than 20,000 kVA, or
   b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
   c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.
2) the monthly billing demand for the Transmission Peak and Intermediate Demand Periods is the greater of:
   a) the maximum measured load in the current billing period, or
   b) a minimum of 40% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

   the monthly billing demand for the Transmission Base Demand Period is the greater of:
   a) the maximum measured load in the current billing period but not less than 20,000 kVA, or

b) a minimum of 40% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 40% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Proposed:
Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 20,000 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Street Lighting Service - Rate ST. LT.
and
Private Outdoor Lighting - Rate P. O. LT.

Street Lighting Service (Rate ST.LT. – Sheet No. 35) and Private Outdoor Lighting Service (Rate P.O.LT. – Sheet No. 36) are being reorganized into two rate schedules. The first schedule will be named Lighting Services (Rate LS) and will be a consolidation of lighting fixtures currently offered. The second schedule will be named Restricted Lighting Service (Rate RLS) and will be a consolidation of lighting fixtures that are in service but no longer available for new or replacement installations. The current and proposed rates are presented below based on the lights to be included in Rate LS and Rate RLS. The lights proposed to be contained in the specific schedule are shown in **bold** type with the current light and rate sheet shown below the proposed light.

Proposed Lighting Service Rate LS

	Current	Rate Per Light Per Month	
	Rate Sheet	Current	Proposed
OVERHEAD SERVICE			
High Pressure Sodium			
462 Cobra Head, 5800 Lum. Std			$ 8.33
5800 Lum. HPS Std	St. Lt. 35	$ 7.90	
472 Cobra Head, 5800 Lum. Orntl			$11.32
5800 Lum. HPS Orntl	St. Lt. 35	$10.73	
463 Cobra Head, 9500 Lum. Std			$ 8.87
9500 Lum. HPS Std	St. Lt. 35	$ 8.41	
473 Cobra Head, 9500 Lum. Orntl			$12.08
9500 Lum. HPS Orntl	St. Lt. 35	$11.45	
464 Cobra Head, 22000 Lum. Std			$13.75
22000 Lum. HPS Std	St. Lt. 35	$13.04	
22000 Lum. Cobra Head HPS Std	P.O.Lt. 36	$13.04	

474 Cobra Head, 22000 Lum. Orntl			$16.96
22000 Lum. HPS Orntl	St. Lt. 35	$16.08	
465 Cobra Head, 50000 Lum. Std			$22.10
50000 Lum. HPS Std	St. Lt. 35	$20.95	
50000 Lum. Cobra Head HPS Std	P.O.Lt. 36	$20.95	
475 Cobra Head, 50000 Lum. Orntl			$23.74
50000 Lum. HPS Orntl	St. Lt. 35	$22.51	
487 Directional, 9500 Lum. Std			$ 8.72
9500 Lum. Directional HPS	P.O.Lt. 36	$ 8.27	
488 Directional, 22000 Lum. Std			$13.13
22000 Lum. Directional HPS	P.O.Lt. 36	$12.45	
489 Directional, 50000 Lum. Std			$18.67
50000 Lum. Directional HPS	P.O.Lt. 36	$17.70	
428 Open Bottom, 9500 Lum. Std			$ 7.55
9500 Lum. Open Bottom HPS	P.O.Lt. 36	$ 7.16	
Metal Halide			
450 Directional, 12000 Lum. Std			$13.75
12000 Lum. Fixture Only Dir. MH	P.O.Lt. 36.3	$13.04	
451 Directional, 32000 Lum. Std			$19.46
32000 Lum. Fixture Only Dir. MH	P.O.Lt. 36.3	$18.45	
452 Directional, 107800 Lum. Std			$40.58
107800 Lum. Fixture Only Dir. MH	P.O.Lt. 36.3	$38.48	

	Current	Rate Per Light Per Month	
	Rate Sheet	Current	Proposed
UNDERGROUND SERVICE			
High Pressure Sodium			
467 Colonial, 5800 Lum. Decorative			$10.47
5800 Lum. Colonial HPS UG	St. Lt. 35.1	$ 9.93	
5800 Lum. Colonial Decor. UG	P.O.Lt. 36.1	$ 9.93	
468 Colonial, 9500 Lum. Decorative			$10.92
9500 Lum. Colonial HPS UG	St. Lt. 35.1	$10.35	
9500 Lum. Colonial Decor. UG	P.O.Lt. 36.1	$10.35	
401 Acorn, 5800 Lum. Smooth Pole			$14.62
5800L Acorn Dec. Pole HPS UG	St. Lt. 35.1	$13.86	
5800L Acorn Dec. Pole UG	P.O.Lt. 36.1	$13.86	
411 Acorn, 5800 Lum. Fluted Pole			$21.24
5800L Acorn Hist. Pole HPS UG	St. Lt. 35.1	$20.14	
5800L Acorn Hist. Pole UG	P.O.Lt. 36.1	$20.14	
420 Acorn, 9500 Lum. Smooth Pole			$15.18
9500L Acorn Dec. Pole HPS UG	St. Lt. 35.1	$14.39	
9500L Acorn Dec. Pole UG	P.O.Lt. 36.1	$14.39	
430 Acorn, 9500 Lum. Fluted Pole			$21.92
9500L Acorn Hist. Pole HPS UG	St. Lt. 35.1	$20.78	
9500L Acorn Hist. Pole UG	P.O.Lt. 36.1	$20.78	
414 Victorian, 5800 Lum. Fluted Pole			$30.84
5800 Lum. Coach HPS UG	P.O.Lt. 36.1	$29.24	
415 Victorian, 9500 Lum. Fluted Pole			$31.27
9500 Lum. Coach HPS UG	P.O.Lt. 36.1	$29.65	
476 Contemporary, 5800 Lum. Fixt./Pole			$16.58
5800 Lum. Contemporary HPS UG	St. Lt. 35.1	$15.66	

5800 Lum. Contemporary HPS UG	P.O.Lt. 36.1	$21.81	
492 Contemporary, 5800 Lum. 2nd Fixt. 5800L Contemp/Fixt. Only/HPS/UG	 P.O.Lt. 36.1	 $14.35	$15.13
477 Contemporary, 9500 Lum. Fixt./Pole 9500 Lum. Contemporary Decor. UG 9500 Lum. Contemporary HPS UG	 St. Lt. 35.1 P.O.Lt. 36.1	 $18.19 $21.85	$20.87
497 Contemporary, 9500 Lum. 2nd Fixt. 9500 Lum. Contemp/Decor/ Fix Only	 P.O.Lt. 36.1	 $14.38	$15.17
478 Contemporary, 22000L Fixt./Pole 22000 Lum. Contemp. Decor. UG 22000 Lum. Contemporary HPS UG	 St. Lt. 35.1 P.O.Lt. 36.1	 $22.11 $27.84	$26.55
498 Contemporary, 22000 Lum. 2nd Fixt. 22000 Lum. Contemp. Add Fixture	 P.O.Lt. 36.1	 $16.37	$17.27
479 Contemporary, 50000L Fixt./Pole 50000 Lum. Contemp. Decor. UG 50000 Lum. Contemporary HPS UG	 St. Lt. 35.1 P.O.Lt. 36.1	 $28.13 $31.12	$32.54
499 Contemporary, 50000 Lum. 2nd Fixt. 50000L Contemp. Decor. Fixt. Only	 P.O.Lt. 36.1	 $19.65	$20.72
300 Dark Sky, 4000 Lumen 4000 Lum. HPS DSK Lantern	 DSK 39	 $21.31	$22.48
301 Dark Sky, 9500 Lumen 9500 Lum. HPS DSK Lantern	 DSK 39	 $22.22	$23.44
360 Granville Pole and Fixture, 16000L Granville Pole and Fixture Granville Pole and Fixture	 St. Lt. 35.1 P.O.Lt. 36.2	 $51.00 $51.00	$53.79
(Granville Accessories)			
Single Crossarm Bracket	St.Lt. 35.1 P.O.Lt. 36.2	$17.78 $17.78	Eliminated Eliminated
Twin Crossarm Bracket (Inc. 1 Fixture)	 St.Lt. 35.1 P.O.Lt. 36.2	 $19.79 $19.79	$20.87
24 Inch Banner Arm	 St.Lt. 35.1 P.O.Lt. 36.2	 $ 3.09 $ 3.09	$ 3.26
24 Inch Clamp Banner Arm	 St. Lt. 35.1 P.O.Lt. 36.2	 $ 4.26 $ 4.26	$ 4.49
18 Inch Banner Arm	 St. Lt. 35.1 P.O.Lt. 36.2	 $ 2.84 $ 2.84	$ 3.00
18 Inch Clamp On Banner Arm	 St. Lt. 35.1 P.O.Lt. 36.2	 $ 3.52 $ 3.52	$ 3.71
Flagpole Holder	 St. Lt. 35.1 P.O.Lt. 36.2	 $ 1.31 $ 1.31	$ 1.38
Post-Mounted Receptacle	 St. Lt. 35.1 P.O.Lt. 36.2	 $18.46 $18.46	$19.47
Base-Mounted Receptacle	St. Lt. 35.1 P.O.Lt. 36.2	$17.81 $17.81	Eliminated Eliminated
Additional Receptacles	 St. Lt. 35.1 P.O.Lt. 36.2	 $ 2.52 $ 2.52	$ 2.66

Planter	St. Lt. 35.1 P.O.Lt. 36.2	$ 4.28 $ 4.28	$ 4.51
Clamp On Planter	St. Lt. 35.1 P.O.Lt. 36.2	$ 4.75 $ 4.75	$ 5.01
Metal Halide			
490 Contemporary, 12000L Fixt. Only 12000 Lum. Contemp. Fix. Only MH	P.O.Lt. 36.3	$14.21	$14.99
494 Contemporary, 12000Lum. Fixture w/Smooth Pole 12000 Lum. Cont. Fix. w/M Pole MH	P.O.Lt. 36.3	$26.62	$28.08
491 Contemporary, 32000 Lum. Fix. Only 32000 Lum. Contemp. Fix. Only MH	P.O.Lt. 36.3	$20.12	$21.22
495 Contemporary, 32000 Lum. Fixture w/Smooth Pole 32000 Lum. Cont. Fix. w/M Pole MH	P.O.Lt. 36.3	$32.53	$34.31
493 Contemporary, 107800L Fixt./Only 107800 Lum. Contemp. Fix. Only MH	P.O.Lt. 36.3	$41.70	$43.98
496 Contemporary, 107800 Lum. Fixture w/Smooth Pole 107800 Lum. Cont. Fix. w/M Pole MH	P.O.Lt. 36.3	$54.11	$57.07

<u>Proposed Restricted Lighting Service Rate RLS</u>

	Current	Rate Per Light Per Month	
	Rate Sheet	Current	Proposed
OVERHEAD SERVICE			
High Pressure Sodium			
461 Cobra Head, 4000 Lum. Fixt. Only 4000 Lum. HPS Std	St. Lt. 35	$ 6.93	$ 7.31
471 Cobra Head, 4000 Lum. Fixt/Pole 4000 Lum. HPS Orntl	St. Lt. 35	$ 9.76	$10.29
409 Cobra Head, 50000 Lum. Fixt. Only 50000 Lum. HPS Special Lighting	P.O.Lt. 36	$10.25	$10.81
426 Open Bottom, 5800 Lum. Fixt. Only 5800 Lum. Open Bottom HPS Std	P.O.Lt. 36	$ 6.72	$ 7.09
Metal Halide			
454 Direct, 12000 Lum. Flood Fixt/Pole 12000L Fixt/Pole Dir. MH	P.O.Lt. 36.3	$17.27	$18.21
455 Direct, 32000 Lum. Flood Fixt/Pole 32000L Fixt/Pole Dir. MH	P.O.Lt. 36.3	$22.68	$23.92
459 Direct, 107800 Lum. Flood Fixt/Pole 107800L Fixt/Pole Dir. MH	P.O.Lt. 36.3	$42.71	$45.05
Mercury Vapor			
446 Cobra Head, 7000 Lum. Fixt. Only 7000 Lum. MV Std	St. Lt. 35	$ 8.72	$ 9.20
456 Cobra Head, 7000 Lum. Fixt/Pole 7000 Lum. MV Orntl	St. Lt. 35	$10.94	$11.54

447 Cobra Head, 10000 Lum. Fixt. Only			$10.85
10000 Lum. MV Std	St. Lt. 35	$10.29	
457 Cobra Head, 10000 Lum. Fixt/Pole			$12.93
10000 Lum. MV Orntl	St. Lt. 35	$12.26	
448 Cobra Head, 20000 Lum. Fixt. Only			$12.19
20000 Lum. MV Std	St. Lt. 35	$12.57	
20000 Lum. MV Special Ltg.	P.O.Lt. 36	$ 7.85	
458 Cobra Head, 20000 Lum. Fixt/Pole			$14.49
20000 Lum. MV Orntl	St. Lt. 35	$14.14	
20000 Lum. Cobra Head MV Std	P.O.Lt. 36	$12.57	
404 Open Bottom, 7000 Lum. Fixt. Only			$10.22
7000 Lum. Open Bottom MV Std	P.O.Lt. 36	$ 9.69	
Incandescent			
421 Tear Drop, 1000 Lum. Fixt. Only			$ 3.25
1000 Lum. Incand. Std	St. Lt. 35	$ 3.08	
422 Tear Drop, 2500 Lum. Fixt. Only			$ 4.31
2500 Lum. Incand. Std	St. Lt. 35	$ 4.09	
424 Tear Drop, 4000 Lum. Fixt. Only			$ 6.41
4000 Lum. Incand. Std	St. Lt. 35	$ 6.08	
434 Tear Drop, 4000 Lum. Fixt. /Pole			$ 7.38
4000 Lum. Incand. Orntl	St. Lt. 35	$ 7.00	
425 Tear Drop, 6000 Lum. Fixt. Only			$ 8.55
6000 Lum. Incand. Std	St. Lt. 35	$ 8.11	

	Current	Rate Per Light Per Month	
	Rate Sheet	Current	Proposed
UNDERGROUND SERVICE			
Metal Halide			
460 Direct, 12000 Lum. Flood Fixt/Pole			$26.84
12000L Fixt. w/M. Pole Dir. MH	P.O.Lt. 36.3	$ 25.45	
469 Direct, 32000 Lum. Flood Fixt/Pole			$32.55
32000L Fixt. w/M. Pole Dir. MH	P.O.Lt. 36.3	$ 30.86	
470 Direct, 107800 Lum. Flood Fixt/Pole			$53.67
107800L Fixt. w/M. Pole Dir. MH	P.O.Lt. 36.3	$ 50.89	
High Pressure Sodium			
440 Acorn, 4000 Lum. Flood Fixt/Pole			$13.47
4000L Acorn (Decor) HPS UG	P.O.Lt. 36.1	$12.77	
410 Acorn, 4000 Lum. Fluted Pole			$20.21
4000L Acorn (Hist Pole) HPS UG	St. Lt. 35.1	$19.16	
4000L Acorn (Hist Pole) HPS UG	P.O.Lt. 36.1	$19.16	
466 Colonial, 4000 Lum. Smooth Pole			$ 9.42
4000 Lum. Colonial HPS UG	St. Lt. 35.1	$ 8.93	
4000 Lum. Colonial Decor. UG	P.O.Lt. 36.1	$ 8.93	
412 Coach, 5800 Lum. Smooth Pole			$30.84
5800 Lum. Coach Decor. UG	St. Lt. 35.1	$ 29.24	
413 Coach, 9500 Lum. Smooth Pole			$31.27
9500 Lum. Coach Decor. UG	St. Lt. 35.1	$ 29.65	

Lighting Energy Service Rate LE

	Current	Proposed
Energy Charge per kWh:	$0.05647	$0.05958

Traffic Energy Service Rate TE

	Current	Proposed
Basic Service Charge per Month:	$3.14	$3.25
Energy Charge per kWh:	$0.07182	$0.07614

Dark Sky Friendly Rate DSK

Current Rate

DSK Lantern	4,000	.050	$21.31
DSK Lantern	9,500	.100	$22.22

Proposed Rate

This rate schedule is proposed to be included in Lighting Service Rate LS.

Cable Television Attachment Charges – Rate CTAC

	Current	Proposed
Attachment Charge per year for each attachment to pole:	$5.40	$10.01

Curtailable Service Rider 10 – Rider CSR10

	Current (per kW)	Proposed (Per kVA)
Monthly Demand Credit:		
Primary	($5.50)	($2.80)
Transmission	($5.40)	($2.75)
Non-Compliance Charge:	$16.00	$16.00

Proposed Contract Option: Removes restriction that KU may only use physical curtailment during system reliability events. Also changes contract options' demand from a 15-minute demand basis to the one the customer's standard rate schedule uses.

Curtailable Service Rider 30 – Rider CSR30

	Current (per kW)	Proposed (Per kVA)
Monthly Demand Credit per kW:		
Primary	($4.40)	($2.30)
Transmission	($4.30)	($2.25)
Non-Compliance Charge per kW:	$16.00	$16.00

Proposed Contract Option: Removes restriction that KU may only use physical curtailment during system reliability events. Also changes contract options' demand from a 15-minute demand basis to the one the customer's standard rate schedule uses.

Load Reduction Incentive Rider – Rider LRI

Current Rate Up to $0.30 per kWh

Proposed Rate This rate schedule is proposed to be eliminated.

Standard Rider for Excess Facilities – Rider EF

Current Rate

Customer shall pay for excess facilities by:

Monthly Charge for Leased Facilities:	1.54%
Monthly Charge for Facilities Supported By a One-Time CIAC Payment:	0.74%

Proposed Rate

No adjustment in the monthly charge for a replacement of facilities will be made during the initial five (5) year term of contract.

Customer shall pay for excess facilities by:

(a) Making a monthly Excess Facilities charge payment equal to the installed cost of the excess facilities times the following percentage:

Percentage with No Contribution-in-Aid-of-Construction	1.28%

(b) Making a one-time Contribution-in-Aid-of-Construction equal to the installed cost of the excess facilities plus a monthly Excess Facilities Charge payment equal to the installed cost of the excess facilities times the following percentage:

Percentage with Contribution-in-Aid-of-Construction	0.49%

Standard Rider for Redundant Capacity Charge – Rider RC

	Current (per kW)	Proposed (Per kVA)
Capacity Reservation Charge per Month:		
Secondary Distribution	$0.85	$1.55
Primary Distribution	$0.68	$0.99

Standard Rider for Supplemental or Standby Service – Rider SS

	Current (per kW)	Proposed (Per kVA)
Contract Demand per month:		
Secondary	$6.54	$12.91
Primary	$6.17	$12.35
Transmission	$5.99	$11.17

Availability of Service: Text addition clarifies that KU has no obligation to supply non-firm service to a customer-generator unless the customer seeks supplemental or standby service under Rider SS. This requirement does not apply to Net Metering Service (Rider NMS).

Temporary and/or Seasonal Electric Service Rider TS

Availability of Service: Text change clarifies that service is available when it is not necessary for KU to install permanent facilities.

Conditions: Customer will pay for non-salvageable materials plus a monthly charge for the salvageable equipment at the Percentage With No Contribution in-Aid-of-Construction specified on the Excess Facilities Rider.

Real-Time Pricing Rider RTP

Current Rate: Billing under this Rider is formulaic.

Proposed Rate: This rate schedule is proposed to be eliminated.

Standard Rate for Low Emission Vehicle Service – Rate LEV

	Current	Proposed

Basic Service Charge per Month:	$8.50	$13.00
Energy Charge per kWh:		
Off-Peak Hours	$0.04904	$ 0.05078
Intermediate Hours	$0.07005	$ 0.07254
Peak Hours	$0.13315	$ 0.13788

Availability of Service: Clarifies that rate is available to customers eligible for Rate RS or GS where the GS service is used in conjunction with an RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month.

Meter Test Charge

Current Rate $60.00
Proposed Rate $75.00

Disconnecting and Reconnecting Service Charge

Current Rate $25.00
Proposed Rate $28.00

Meter Pulse Charge

Current Rate:
$9.00 per month per installed set of pulse-generating equipment
Proposed Rate:
$15.00 per month per installed set of pulse-generating equipment

Customer Deposits

KU is proposing no change to the required Customer Deposit for residential electric customers served under Residential Rate RS from the current amount of $135.00 (0% increase), and the required Customer Deposit for general service customers served under General Service Rate GS from the current amount of $220.00 (0% increase). Text change states when Rate GS deposit may be waived in conjunction with taking service under Rate RS.

Kentucky Utilities Company proposes to change the text of the following electric tariffs: General Service Rate GS, All Electric School Rate AES, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, Retail Transmission Service Rate RTS, Fluctuating Load Service Rate FLS, Street Lighting Service Rate ST. LT, Private Outdoor Lighting Rate P.O.LT, Cable Television Attachment Charges Rate CTAC, Curtailable Service Rider CSR10, Curtailable Service Rider CSR30, Excess Facilities Rider EF, Redundant Capacity Rider RC, Supplemental/Standby Service Rider SS, Rider IL for Intermittent Loads, Temporary/Seasonal Service Rider TS, Large Green Energy Rider LGE, Low Emission Vehicle Service Rate LEV, Fuel Adjustment Clause FAC, Demand Side Management Cost Recovery Mechanism DSM, Environmental Cost Recovery Surcharge ECR, and the Terms and Conditions.

Changes to the Terms and Conditions include proposed clarifications on terms and conditions for determining customer rate assignments, as well as when standby or supplemental service must be purchased if customer desires non-firm service.

Although KU is not proposing to change the text of its Fuel Adjustment Clause ("FAC"), other than the correction of a minor typographical error in Paragraph (3), it is proposing to recover certain costs through the FAC to ensure that the correct amounts are collected through base rates and the FAC.

Complete copies of the proposed tariffs containing text changes and proposed rates may be obtained by contacting Lonnie E. Bellar, Kentucky Utilities Company at 220 West Main Street, Louisville, Kentucky, 502-627-4830, or visiting Kentucky Utilities Company's website at www.lge-ku.com.

The foregoing rates reflect a proposed annual increase in revenues of approximately 6.5% to Kentucky Utilities Company.

The estimated amount of the annual change and the average monthly bill to which the proposed electric rates will apply for each electric customer class is as follows:

Electric Rate Class	Annual $ Increase	Annual % Increase	Mthly Bill $ Increase	Mthly Bill % Increase
Residential	$37,381,886	8.03%	$ 7.41	8.03%
General Service	$ 9,061,201	4.97%	$ 9.20	4.97%
All Electric School	$ 635,467	5.81%	$ 82.81	5.81%
Power Service	$ 6,849,989	2.53%	$ 96.29	2.53%
TODS (Secondary)	$ 1,907,198	6.59%	$ 1,160.80	6.59%
TODP (Primary)	$12,380,611	6.62%	$ 6,159.51	6.62%
Retail Transmission	$ 5,128,398	6.50%	$ 11,982.24	6.50%
Fluctuating Load	$ 1,417,956	6.25%	$118,163.01	6.25%
Outdoor Lights	$ 1,267,776	5.41%	$ 0.62	5.41%
Lighting Energy	$ 124	5.42%	$ 11.27	5.42%
Traffic Energy	$ 6,388	5.40%	$ 0.79	5.40%
CTAC	$ 681,722	85.37%	N/A	N/A

The rates contained in this notice are the rates proposed by Kentucky Utilities Company; however, the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice.

Notice is further given that any corporation, association, body politic or person with a substantial interest in the matter may by written request, within thirty (30) days after publication of the notice of the proposed rate changes, request to intervene. The motion shall be submitted to the Public Service Commission, 211 Sower Boulevard, P. O. Box 615, Frankfort, Kentucky 40601, and shall set forth the grounds for the request, including the status and interest of the party. Intervention may be granted beyond the thirty (30) day period for good cause shown. Any person who has been granted intervention may obtain copies of the application and any other filing made by the utility by contacting Lonnie E. Bellar, Vice President – State Regulation and Rates, Kentucky Utilities Company, c/o LG&E and KU Energy LLC, 220 West Main Street, Louisville, Kentucky, 502-627-4830.

A copy of the application and testimony shall be available for public inspection at the office of Kentucky Utilities Company, 100 Quality Street, Lexington, Kentucky, or the Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky.

A copy of this Notice and the proposed tariff, once filed, shall also be available for public inspection on Kentucky Utilities Company's website at www.lge-ku.com.

Kentucky Utilities Company	Public Service Commission
c/o LG&E and KU Energy LLC	211 Sower Boulevard
220 West Main Street	P. O. Box 615
P. O. Box 32010	Frankfort, Kentucky 40601
Louisville, Kentucky 40232	502-564-3940
502-627-4830	

KENTUCKY PRESS SERVICE

101 Consumer Lane Frankfort, KY 40601
(502) 223-8821 FAX (502) 875-2624
Rachel McCarty Advertising Dept.

List of newspapers scheduled to run Kentucky Utilities Company Notice.

Barbourville Mnt. Advocate
Bardstown KY Standard
Bardwell Carlilse Co. News
Bardwell Carlilse Weekly
Beattyville Enterprise
Bedford Trimble Banner
Berea Citizen
Brooksville Bracken Co.
Brownsville Edmonson New
Calhoun McLean Co. New
Campbellsville Central KY
Carlisle Mercury
Carrollton News Democrat
Cave City Barren Prorgress
Central City Leader News
Central City Times Argus
Clinton Hickman Co. Gaz
Columbia Adair Progress
Corbin Times Tribune
Cumberland Tri City News
Cynthiana Democrat
Dawson Springs Progress
Eddyville Herald Ledger
Elizabetthtown Hardin Inde
Elizabethtown News Enter
Falmouth Outlook
Flemingsburg Gazette
Florence Boone Co Recorder
Frankfort State Journal
Fulton Leader
Georgetown Graphic
Glasgow Daily Times
Greensburg Record Herald
Harlan Enterprise
Harrodsburg Herald
Hartford Ohio Co Times
Henderson Gleaner
Hickman Courier
Hodgenville Larue Herald
Hopkinsville KY New Era
Irvine Citizen Voice Times
Irvine Estill Co. Tribune
Lagrange Oldham Era
Lancaster Central Record
Lawrenceburg Anderson News
Lebanon Enterprise
Leitchfield News Gazette
Leitchfield Record
Lexington Herald Leader
Liberty Casey Co. News
London Sentinel Echo
Louisville Courier Journal
Madisonville Messenger
Manchester Enterprise
Marion Crittenden Press
Maysville Ledger Indep
Middlesboro Daily News
Morehead News
Morganfield Union Co
Mt. Sterling Advocate
Mt. Vernon Signal
Munfordville Hart Co. News
New Castle Henry Co. Local
Nicholasville Jessamine
Owensboro Messneger Inq
Owenton News Herald
Owingsville Bath Co. Outlook
Paducah Sun
Paris Bourbon Citizen
Pineville Sun
Princeton Times Leader
Providence Journal Enter
Richmond Register
Robertson Co. News
Russell Springs Times

Sebree Banner
Shelbyville Sentinel News
Shepherdsville Pioneer
Smithland Livingston Ledger
Somerset Commonwealth
Springfield Sun
Stanford Interior Journal
Sturgis News
Taylorsville Spencer Magnet
The Advocate Messenger
Three Forks Tradition
Versailles Woodford Sun
Warsaw Gallatin News
Whitley City McCreary Record
Whitley City McCreary Voice
Wickliffe Advance Yeoman
Williamsburg News Journal
Williamstown Grant Co. News
Wincheter Sun

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(2)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

Notice of Intent. Utilities with gross annual revenues greater than $1,000,000 shall file with the commission a written notice of intent to file a rate application at least four (4) weeks prior to filing their application. The notice of intent will state whether the rate application shall be supported by a historical test period or a fully forecasted test period. This notice shall be served upon the Attorney General, Utility Intervention and Rate Division.

Response:

See attached.

a PPL company

Kentucky Utilities Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Lonnie E. Bellar
Vice President
T 502-627-4830
F 502-217-2109
lonnie.bellar@lge-ku.com

Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

RECEIVED

JUN 01 2012

PUBLIC SERVICE
COMMISSION

June 1, 2012

RE: ***Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*** **– Case No. 2012-00______**

Dear Mr. DeRouen:

Please take notice that Kentucky Utilities Company ("KU") intends to file on or after June 29, 2012, a rate application for a general adjustment in its electric rates, including changes to its electric tariffs. The application will be supported by a historic test year ending March 31, 2012.

KU has contemporaneously filed a Request to Use Electronic Case Filing. Please assign this matter a case number and style and advise us of same so that it can be incorporated in the application and supporting testimony before filing with the Commission.

Sincerely,

Lonnie E. Bellar

cc: Dennis G. Howard II
Michael L. Kurtz

Description of Filing Requirement:

Form of notice to customers. Every utility filing an application pursuant to this section shall notify all affected customers in the manner prescribed herein. The notice shall include the following information:

(a) The amount of the change requested in both dollar amounts and percentage change for each customer classification to which the proposed rate change will apply;

(b) The present rates and the proposed rates for each customer class to which the proposed rates would apply;

(c) Electric, gas, water and sewer utilities shall include the effect upon the average bill for each customer class to which the proposed rate change will apply;

(d) Local exchange companies shall include the effect upon the average bill for each customer class for the proposed rate change in basic local service;

(e) A statement that the rates contained in this notice are the rates proposed by (name of utility); however, the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice;

(f) A statement that any corporation, association, or person with a substantial interest in the matter may, by written request, within thirty (30) days after publication or mailing of this notice of the proposed rate changes request to intervene; intervention may be granted beyond the thirty (30) day period for good cause shown;

(g) A statement that any person who has been granted intervention by the commission may obtain copies of the rate application and any other filings made by the utility by contacting the utility through a name and address and phone number stated in this notice;

(h) A statement that any person may examine the rate application and any other filings made by the utility at the main office of the utility or at the commission's office indicating the addresses and telephone numbers of both the utility and the commission; and

Description of Filing Requirement (continued):

(i) The commission may grant a utility with annual gross revenues greater than $1,000,000, upon written request, permission to use an abbreviated form of published notice of the proposed rates provided the notice includes a coupon which may be used to obtain all of the information required herein.

Response:

Please refer to the Certificate of Notice provided in Filing Requirement 807 KAR 5:001 Section 10(1)(a)9, [Tab No. 9].

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(4)(a)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

Manner of notification. Sewer utilities shall give the required typewritten notice by mail to all of their customers pursuant to KRS 278.185.

Response:

Not applicable to KU's Application.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(4)(b)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

Manner of notification. Applicants with twenty (20) or fewer customers affected by the proposed general rate adjustment shall mail the required typewritten notice to each customer no later than the date the application is filed with the commission.

Response:

Not applicable to KU's Application.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(4)(c)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

Manner of notification. Except for sewer utilities, applicants with more than twenty (20) customers affected by the proposed general rate adjustment shall give the required notice by one (1) of the following methods:

1. *A typewritten notice mailed to all customers no later than the date the application is filed with the commission;*

2. *Publishing the notice in a trade publication or newsletter which is mailed to all customers no later than the date on which the application is filed with the commission; or*

3. *Publishing the notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made within seven (7) days of the filing of the application with the commission.*

Response:

KU has complied with 807 KAR 5:001, Section 10(4)(c) by delivering to the Kentucky Press Association, an agency that acts on behalf of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, for publication in such newspapers once a week for three consecutive weeks in a prominent manner, a copy of the notice is attached to the Certificate of Notice provided in Filing Requirement 807 KAR 5:001 Section 10(1)(a)9, [Tab No. 9]; the first of said publications to be made within seven (7) days of the filing of the application, as set forth in the Certificate of Notice provided in Filing Requirement 807 KAR 5:001 Section 10(1)(a)9, [Tab No. 9].

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(4)(d)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

Manner of notification. If the notice is published, an affidavit from the publisher verifying the notice was published, including the dates of the publication with an attached copy of the published notice, shall be filed with the commission no later than forty-five (45) days of the filed date of the application.

Response:

KU will comply with 807 KAR 5:011, Section 10(4)(d) by providing the affidavits within forty-five (45) days of the date on which KU filed its application.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(4)(e)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

Manner of notification. If the notice is mailed, a written statement signed by the utility's chief officer in charge of Kentucky operations verifying the notice was mailed shall be filed with the commission no later than thirty (30) days of the filed date of the application.

Response:

Not applicable to KU’s Application.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(4)(f)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

Manner of notification. All utilities, in addition to the above notification, shall post a sample copy of the required notification at their place of business no later than the date on which the application is filed which shall remain posted until the commission has finally determined the utility's rates.

Response:

KU has complied with 807 KAR 5:001, Section 10(4)(f) by posting its Notice, attached to the Certificate of Notice provided in Filing Requirement 807 KAR 5:001 Section 10(1)(a)9, [Tab No. 9], at its places of business on June 29, 2012, and said Notice will remain posted until the Commission has finally determined the utility’s rates, as set forth in the Certificate of Notice provided in Filing Requirement 807 KAR 5:001 Section 10(1)(a)9, [Tab No. 9].

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(4)(g)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

Manner of notification. Compliance with this subsection shall constitute compliance with 807 KAR 5:051, Section 2.

Response:

No response is required.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(5)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

Notice of hearing scheduled by the commission upon application by a utility for a general adjustment in rates shall be advertised by the utility by newspaper publication in the areas that will be affected in compliance with KRS 424.300.

Response:

KU will comply with 807 KAR 5:001, Section 10(5) by publishing the Notice of Hearing in the newspapers in the areas affected. KU's advertisement of the Notice of Hearing shall comply with KRS 424.300.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(a)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

All applications supported by a historical test period shall include the following information or a statement explaining why the required information does not exist and is not applicable to the utility's application: (a) A complete description and quantified explanation for all proposed adjustments, with proper support for any proposed changes in price or activity levels, and any other factors which may affect the adjustment.

Response:

Please refer to the testimonies and exhibits of Kent W. Blake, Valerie L. Scott, Shannon L. Charnas, John J. Spanos, Daniel K. Arbough, William E. Avera, Lonnie E. Bellar, and Robert M. Conroy.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(b)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

If the utility has gross annual revenues greater than $1,000,000, the prepared testimony of each witness the utility proposes to use to support its application.

Response:

Please refer to the testimonies and exhibits of the following persons:

- Victor S. Staffieri
- Paul W. Thompson
- Chris Hermann
- Kent W. Blake
- Valerie L. Scott
- Shannon L. Charnas
- John J. Spanos
- Daniel K. Arbough
- William E. Avera
- Lonnie E. Bellar
- Robert M. Conroy

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(c)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

If the utility has gross annual revenues less than $1,000,000, the prepared testimony of each witness the utility proposes to use to support its application or a statement that the utility does not plan to submit any prepared testimony.

Response:

Not applicable to KU's Application.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(d)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A statement estimating the effect that the new rates will have upon the revenues of the utility including, at minimum, the total amount of revenues resulting from the increase or decrease and the percentage of the increase or decrease.

Response:

The proposed rates (including miscellaneous charges) will increase KU's annual electric revenues approximately $82,432,892 or 6.5%.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(e)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

If the utility provides electric, gas, water, or sewer service the effect upon the average bill for each customer classification to which the proposed rate change will apply.

Response:

The average monthly bill, for each customer rate class to which the proposed rate change applies, will increase as follows:

Electric Rate Class	Annual $ Increase	Annual % Increase	Mthly Bill $ Increase	Mthly Bill % Increase
Residential	$37,381,886	8.03%	$ 7.41	8.03%
General Service	$ 9,061,201	4.97%	$ 9.20	4.97%
All Electric School	$ 635,467	5.81%	$ 82.81	5.81%
Power Service	$ 6,849,989	2.53%	$ 96.29	2.53%
TODS (Secondary)	$ 1,907,198	6.59%	$ 1,160.80	6.59%
TODP (Primary)	$12,380,611	6.62%	$ 6,159.51	6.62%
Retail Transmission	$ 5,128,398	6.50%	$ 11,982.24	6.50%
Fluctuating Load	$ 1,417,956	6.25%	$118,163.01	6.25%
Outdoor Lights	$ 1,267,776	5.41%	$ 0.62	5.41%
Lighting Energy	$ 124	5.42%	$ 11.27	5.42%
Traffic Energy	$ 6,388	5.40%	$ 0.79	5.40%
CTAC	$ 681,722	85.37%	N/A	N/A

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(f)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

If the utility is a local exchange company, the effect upon the average bill for each customer class for the proposed rate change in basic local service.

Response:

Not applicable to KU's Application.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(g)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

An analysis of customers' bills in such detail that revenues from the present and proposed rates can be readily determined for each customer class.

Response:

Please refer to the testimony and exhibits of Robert M. Conroy.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(h)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

A summary of the utility's determination of its revenue requirements based on return on net investment rate base, return on capitalization, interest coverage, debt service coverage, or operating ratio, with supporting schedules.

Response:

See attached. Supporting Schedules are filed as part of the Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab No. 42] and Kent W. Blake Exhibit 8.

Kentucky Utilities Company
Revenue Requirement as of March 31, 2012

1	Fuel	432,973,775	(1)
2	Purchased Power	90,060,701	(2)
3	Operations and Maintenance	287,240,864	(3)
4	Depreciation and Amortization Expense	168,354,713	(4)
5	Regulatory Credits	(5,207,773)	(5)
6	Taxes Other Than Income Taxes	25,929,743	(6)
7	Net Operating Income Found Reasonable	251,055,038	(7)
8	Income Tax	117,722,320	(8)
9	Gains from Disposition of Allowances	(767)	(9)
10	Accretion Expense	2,542,421	(10)
11	Total Cost of Service (Revenue Requirement)	1,370,671,035	
12	Revenues at Present Rates	1,287,695,102	(11)
13	Revenue Deficiency	82,975,933	(12)

(1) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] income statement, line 11
(2) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] income statement, line 12
(3) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] income statement, line 13
(4) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] income statement, line 14
(5) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] income statement, line 15
(6) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] income statement, line 16
(7) See Blake Exhibit 8, line 3
(8) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] income statement, line 17 ($86,940,494) and Blake Exhibit 8, line 7 - line 5 ($30,781,826)
(9) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] income statement, line 19
(10) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] income statement, line 18
(11) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] income statement, line 8
(12) See Blake Exhibit 8, line 7

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(i)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

A reconciliation of the rate base and capital used to determine its revenue requirement.

Response:

See attached.

KENTUCKY UTILITIES COMPANY

Reconciliation of Capitalization and Net Original Cost Rate Base

Line No.		Total Company Balance as of 3/31/2012	Kentucky Jurisdictional	Other Jurisdictional
1	Rate Base Percentage (Exhibit 3, Line 19)		87.52%	12.48%
2	Capitalization:			
3	Common Equity	$ 2,138,484,751		
4	Long-Term Debt	1,840,750,374		
5	Subtotal	$ 3,979,235,125	$ 3,482,626,581	$ 496,608,544
6	Adjustments to Capitalization:			
7	Undistributed Subsidiary Earnings	(3,158,501)	(2,764,320)	(394,181)
8	Investment in EEI	(1,295,800)	(1,134,084)	(161,716)
9	Investment in OVEC and Other	(429,121)	(375,567)	(53,554)
10	Environmental Compliance Plans	(183,667,066)	(183,667,066)	-
11	Subtotal	(188,550,488)	(187,941,037)	(609,451)
12				
13	Total Capitalization As Filed	$ 3,790,684,637	$ 3,294,685,544	$ 495,999,093
14				
15	Assets per books not included in rate base:			
16	Net ARO Assets	(53,586,286)	(46,378,395)	(7,207,891)
17	Other Property & Investments	(5,169,395)	(4,524,255)	(645,140)
18	Misc. Current Assets	(887)	(776)	(111)
19	Unamortized Debt Expense	(20,993,396)	(18,373,420)	(2,619,976)
20	Unamortized Loss on Bonds	(11,623,874)	(10,173,215)	(1,450,659)
21	Deferred Regulatory Assets	(267,700,866)	(234,291,798)	(33,409,068)
22	Other Deferred Debits	(45,907,397)	(40,178,154)	(5,729,243)
23	Accumulated Deferred Income Taxes	(5,512,040)	(4,824,137)	(687,903)
24	Subtotal	(410,494,141)	(358,744,150)	(51,749,991)
25				
26	Liabilities per books not included in rate base:			
27	Other Deferred Credits	12,482,364	10,924,565	1,557,799
28	Regulatory Liabilities	105,461,190	92,333,990	13,127,200
29	ARO Liabilities	62,573,226	54,764,087	7,809,139
30	Misc. Long-term Liabilities	2,630,531	2,302,241	328,290
31	Accumulated Provision for Pension & Postretirement	134,724,223	117,910,640	16,813,583
32	Subtotal	317,871,534	278,235,523	39,636,011
33				
34	Capitalization per books not included in rate base:			
35	Undistributed Subsidiary Earnings	3,158,501	2,764,320	394,181
36				
37	Items included in rate base:			
38	Inventory - 13 month average vs. end of period	1,730,751	461,731	1,269,020
39	Allowances - 13 month average vs. end of period	64,777	52,030	12,747
40	Prepayments - 13 month average vs. end of period	1,330,746	1,319,829	10,917
41	Environmental Compliance Plans	183,667,066	183,667,066	-
42	Cash Working Capital Formula vs. Actual	111,920,018	102,963,487	8,956,531
43	Capitalization / Rate Base Allocation Differences	-	(4,470,234)	4,470,234
44	Subtotal	298,713,358	283,993,909	14,719,449
45				
46	Total Reconciliation	209,249,252	206,249,602	2,999,650
47				
48	Total Net Original Cost Rate Base (Exhibit 3, Line 18)	$ 3,999,933,889	$ 3,500,935,146	$ 498,998,743

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(j)
Sponsoring Witness: Valerie L. Scott

Description of Filing Requirement:

A current chart of accounts if more detailed than the Uniform System of Accounts prescribed by the commission.

Response:

See attached.

Account	Account Description
101101	PROPERTY UNDER CAPITAL LEASES
101102	PLANT IN SERVICE - ELECTRIC FRANCHISES AND CONSENTS
101103	PLANT IN SERVICE - MISC. INTANGIBLE PLANT
101104	PLANT IN SERVICE - ELECTRIC LAND
101105	PLANT IN SERVICE - ELECTRIC STRUCTURES
101106	PLANT IN SERVICE - ELECTRIC EQUIPMENT
101107	PLANT IN SERVICE - ELECTRIC ARO ASSET RETIREMENT COST-EQUIPMENT
101108	PLANT IN SERVICE - ELECTRIC HYDRO EQUIPMENT
101109	PLANT IN SERVICE - ELECTRIC DISTRIBUTION EQUIPMENT
101110	PLANT IN SERVICE - LEASED PROPERTY
101111	PLANT IN SERVICE - ELECTRIC GENERAL EQUIPMENT
101112	PLANT IN SERVICE - ELECTRIC COMMUNICATION EQUIPMENT
101113	PLANT IN SERVICE - ELECTRIC LAND RIGHTS
101125	PLANT IN SERVICE - ELECTRIC ARO ASSET RETIREMENT COST-LAND/BUILDING
101202	PLANT IN SERVICE - GAS FRANCHISES AND CONSENTS
101204	PLANT IN SERVICE - GAS LAND
101205	PLANT IN SERVICE - GAS STRUCTURES
101206	PLANT IN SERVICE - GAS UNDERGROUND AND TRANSMISSION EQUIPMENT
101207	PLANT IN SERVICE - GAS ARO ASSET RETIREMENT COST-EQUIPMENT
101208	PLANT IN SERVICE - GAS TRANSPORTATION EQUIPMENT
101209	PLANT IN SERVICE - GAS DISTRIBUTION EQUIPMENT
101211	PLANT IN SERVICE - GAS GENERAL EQUIPMENT
101213	PLANT IN SERVICE - GAS LAND RIGHTS
101225	PLANT IN SERVICE - GAS ARO ASSET RETIREMENT COST-LAND/BUILDING
101301	PLANT IN SERVICE - COMMON ORGANIZATION
101302	PLANT IN SERVICE - COMMON FRANCHISES AND CONSENTS
101303	PLANT IN SERVICE - COMMON MISC. INTANGIBLE PLANT
101304	PLANT IN SERVICE - COMMON LAND
101305	PLANT IN SERVICE - COMMON STRUCTURES
101311	PLANT IN SERVICE - COMMON GENERAL EQUIPMENT
101312	PLANT IN SERVICE - COMMON COMMUNICATION EQUIPMENT
101313	PLANT IN SERVICE - COMMON LAND RIGHTS
101315	PLANT IN SERVICE - COMMON GENERAL EQUIPMENT
101325	PLANT IN SERVICE - COMMON ARO ASSET RETIREMENT COST-LAND/BUILDING
102001	ELECTRIC PLANT-PURCHASED OR SOLD
105001	PLT HELD FOR FUT USE
106103	COMPL CONST NOT CL - MISC. INTANGIBLE PLANT
106104	COMPL CONST NOT CL - ELECTRIC LAND
106105	COMPL CONST NOT CL - ELECTRIC STRUCTURES
106106	COMPL CONST NOT CL - ELECTRIC EQUIPMENT
106108	COMPL CONST NOT CL - ELECTRIC HYDRO EQUIPMENT
106109	COMPL CONST NOT CL - ELECTRIC DISTRIBUTION EQUIPMENT
106111	COMPL CONST NOT CL - ELECTRIC GENERAL EQUIPMENT
106112	COMPL CONST NOT CL - ELECTRIC COMMUNICATION EQUIPMENT
106113	COMPL CONST NON CL-ELECTRIC LAND RIGHTS
106205	COMPL CONST NOT CL - GAS STRUCTURES
106206	COMPL CONST NOT CL - GAS UGD AND TRANSMISSION EQUIP
106208	COMPL CONST NOT CL - GAS TRANSPORTATION EQUIPMENT
106209	COMPL CONST NOT CL - GAS DISTRIBUTION EQUIPMENT
106211	COMPL CONST NOT CL - GAS GENERAL EQUIPMENT
106213	COMPL CONST NON CL-GAS LAND RIGHTS
106303	COMPL CONST NOT CL - COMMON MISC. INTANGIBLE PLANT
106305	COMPL CONST NOT CL - COMMON STRUCTURES
106311	COMPL CONST NOT CL - COMMON GENERAL EQUIPMENT
106312	COMPL CONST NOT CL - COMMON COMMUNICATION EQUIPMENT
106313	COMPL CONST NON CL-COMMON LAND RIGHTS
106315	COMPL CONST NOT CL - COMMON GENERAL EQUIPMENT
107001	CONSTR WORK IN PROG
107005	CLOSED 04/11 - CWIP - PAA FOR PENSION ASSETS
108015	ACCUM DEPR-DISTRIBUTION
108104	ACCUM. DEPR. - ELECTRIC LAND RIGHTS
108105	ACCUM. DEPR. - ELECTRIC STRUCTURES
108106	ACCUM. DEPR. - ELECTRIC EQUIPMENT
108107	ACCUM. DEPR. - ELECTRIC ARO ASSET RETIREMENT COST-EQUIPMENT
108108	ACCUM. DEPR. - ELECTRIC HYDRO EQUIPMENT
108109	ACCUM. DEPR. - ELECTRIC DISTRIBUTION EQUIPMENT
108110	ACCUM. DEPR. - LEASED PROPERTY
108111	ACCUM. DEPR. - ELECTRIC GENERAL EQUIPMENT
108112	ACCUM. DEPR. - ELECTRIC COMMUNICATION EQUIP.
108113	ACCUM. DEPR. - ELECTRIC TRANSPORTATION EQUIP.
108114	ACCUM. DEPR. - COR - ELECTRIC LAND RIGHTS

Account	Account Description
108115	ACCUM. DEPR. - COR - ELECTRIC STRUCTURES
108116	ACCUM. DEPR. - COR - ELECTRIC EQUIPMENT
108118	ACCUM. DEPR. - COR - ELECTRIC HYDRO EQUIPMENT
108119	ACCUM. DEPR. - COR - ELECTRIC DISTRIBUTION
108120	ACCUM. DEPR. - COR - ELECTRIC GENERAL PROPERTY
108121	ACCUM. DEPR. - COR - ELECTRIC COMMUNICATION EQUIP.
108122	ACCUM. DEPR. - COR - LEASED PROPERTY
108125	ACCUM. DEPR. - ELECTRIC ARO ASSET RETIREMENT COST-LAND/BUILDING
108204	ACCUM. DEPR. - GAS LAND RIGHTS
108205	ACCUM. DEPR. - GAS STRUCTURES
108206	ACCUM. DEPR. - GAS UNDERGROUND & TRANSMISSION EQUIPMENT
108207	ACCUM. DEPR. - GAS ARO ASSET RETIREMENT COST-EQUIPMENT
108209	ACCUM. DEPR. - GAS DISTRIBUTION EQUIPMENT
108211	ACCUM. DEPR. - GAS GENERAL EQUIP.
108213	ACCUM. DEPR. - GAS TRANSPORTATION EQUIP.
108215	ACCUM. DEPR. - COR - GAS STRUCTURES
108216	ACCUM. DEPR. - COR - GAS UNDERGROUND & TRANSMISSION EQUIP.
108219	ACCUM. DEPR. - COR - GAS DISTRIBUTION EQUIPMENT
108220	ACCUM. DEPR. - COR - GAS GENERAL EQUIP.
108225	ACCUM. DEPR. - GAS ARO ASSET RETIREMENT COST-LAND/BUILDING
108304	ACCUM. DEPR. - COMMON LAND RIGHTS
108305	ACCUM. DEPR. - COMMON STRUCTURES
108311	ACCUM. DEPR. - COMMON GENERAL EQUIPMENT
108312	ACCUM. DEPR. - COMMON COMMUNICATION EQUIPMENT
108313	ACCUM. DEPR. - COMMON TRANSPORTATION EQUIP.
108314	ACCUM. DEPR. - COMMON GENERAL EQUIPMENT - NONUTILITY
108315	ACCUM. DEPR. - COR - COMMON STRUCTURES
108321	ACCUM. DEPR. - COR - COMMON EQUIPMENT
108325	ACCUM. DEPR. - COMMON ARO ASSET RETIREMENT COST-LAND/BUILDING
108414	ACCUM. DEPR. - SALVAGE - ELECTRIC LAND RIGHTS
108415	ACCUM. DEPR. - SALVAGE - ELECTRIC STRUCTURES
108416	ACCUM. DEPR. - SALVAGE - ELECTRIC EQUIPMENT
108418	ACCUM. DEPR. - SALVAGE - ELECTRIC HYDRO EQUIPMENT
108419	ACCUM. DEPR. - SALVAGE - ELECTRIC DISTRIBUTION
108420	ACCUM. DEPR. - SALVAGE - ELECTRIC GENERAL PROPERTY
108421	ACCUM. DEPR. - SALVAGE - ELECTRIC COMMUNICATION EQUIP.
108515	ACCUM. DEPR. - SALVAGE - GAS STRUCTURES
108516	ACCUM. DEPR. - SALVAGE - GAS UNDERGROUND & TRANSMISSION EQUIP.
108519	ACCUM. DEPR. - SALVAGE - GAS DISTRIBUTION EQUIPMENT
108520	ACCUM. DEPR. - SALVAGE - GAS GENERAL EQUIP.
108615	CLOSED 05/11 - ACCUM. DEPR. - SALVAGE - COMMON STRUCTURES
108621	ACCUM. DEPR. - SALVAGE - COMMON EQUIPMENT
108622	ACCUM. DEPR. - SALVAGE - COMMON COMMUNICATION EQUIPMENT
108799	RWIP-ARO LEGAL
108901	RETIREMENT - RWIP
111102	AMORTIZATION EXPENSE - ELECTRIC FRANCHISES AND CONSENTS
111103	AMORTIZATION EXPENSE - ELECTRIC INTANGIBLES
111202	AMORTIZATION EXPENSE - GAS FRANCHISES AND CONSENTS
111302	AMORTIZATION EXPENSE - COMMON FRANCHISES AND CONSENTS
111303	AMORTIZATION EXPENSE - COMMON INTANGIBLES
117001	GAS STORED-NONCUR
117101	GAS STORED - NONCURRENT RECOVERABLE BASE GAS
121001	NONUTIL PROP IN SERV
121007	PLANT IN SERVICE - ELECTRIC ARO ASSET RETIREMENT COST-EQUIPMENT
121103	MACHINERY & EQUIPMENT
121105	LEASEHOLD IMPROVEMENTS
121106	COMPUTER EQUIPMENT
121107	FURNITURE & FIXTURES
121108	COMPUTER SOFTWARE
122001	ACCUM DEPR/DEPL
122002	ACCUM AMORT-NONUTIL
122007	ACCUM. DEPR. - ELECTRIC ARO ASSET RETIRMENT COST-EQUIPMENT
122203	MACHINERY & EQUIPMENT - ACCUM DEPRECIATION
122205	LEASEHOLD IMPROVEMENTS - ACCUM DEPRECIATION
122206	COMPUTER EQUIPMENT - ACCUM DEPRECIATION
122207	FURNITURE & FIXTURES - ACCUM DEPRECIATION
122208	COMPUTER SOFTWARE - ACCUM DEPRECIATION
123102	INVESTMENT IN LGE PA ADJS
123103	INVEST IN LGE
123104	INVEST IN LGE CAPITAL
123105	INVESTMENT IN KU

Account	Account Description
123108	INVEST IN LEM
123109	INVEST IN SERVCO
123110	CLOSED 04/12 - INVEST IN LPI
123111	INVEST IN LII
123112	INVEST IN HOME SERVICES
123116	INVEST IN WKE
123118	INVEST IN FCD LLC
123122	INVESTMENT IN EEI
123123	INVESTMENT IN OVEC
123124	INVESTMENT IN DHA
123125	INVEST IN LGE CAPITAL PA ADJS
123126	INVEST IN HOME SERVICES PA ADJS
123127	INVEST IN SERVCO PA ADJS
123128	INVEST IN WKE PA ADJS
123129	INVEST IN FCD LLC PA ADJS
123130	INVEST IN LEM PA ADJS
123131	INVEST IN LII PA ADJS
123132	INVEST IN ARGENTINA III PA ADJS
123133	INVEST IN DOWNTOWN COMMERICAL LOAD FUND
123174	INVEST IN ARGENTINA I
123175	INVESTMENT IN KU PA ADJS
123179	INVEST IN ARGENTINA III
123180	INVEST IN LGE POWER DEVELOPMENT
123181	INVEST IN LGE POWER OPERATIONS
128023	PREPAID PENSION
128026	COLLATERAL DEPOSIT - IR SWAPS
128027	RESTRICTED CASH - NON-CURRENT
131006	BBANDT (formerly BANK OF LOUISVILLE)
131011	LEM CASH ACCOUNT
131013	FARMERS BANK
131014	CASH-US BANK
131018	CLOSED 04/11 - NAT CITY BK-$8.90 PREF ACCT
131020	CLOSED 04/11 - NAT CITY BK-$7,45 PREF ACCT
131022	CLOSED 04/11 - CITIBANK
131033	US BANK (formerly FIRSTAR)
131034	BEDFORD LOAN & DEPOSIT BANK
131050	SUNDRY CASH COLLECT
131069	CASH CLEARING - CCS
131080	CASH LOCKBOX-BOA
131090	CASH-BOA A/P - CLEARING
131091	CASH-BOA PAYROLL
131092	CASH-BOA FUNDING
131203	U S BANK - FORMERLY FIRSTAR
131204	BOA - REGULUS
131205	FIRST SOUTHERN NATIONAL BANK
131206	US BANK (E-TOWN)
131207	FIRST UNITED BANK OF HOPKINS COUNTY
131208	BB&T [AREA BANK 0028301978]
131209	FIRST NATIONAL BANK
131210	FIFTH THIRD BANK
131211	US BANK (GEORGETOWN)
131212	US BANK (WINCHESTER)
131213	U S BANK - FORMERLY FIRSTAR
131214	CITIZENS BANK & TRUST CO.
131215	U S BANK - FORMERLY FIRSTAR
131216	US BANK (MT. STERLING)
131217	U S BANK - FORMERLY FIRSTAR
131218	U S BANK - FORMERLY FIRSTAR
131221	US BANK (VERSAILLES)
131223	CITIZENS BANK
131224	KENTUCKY BANK
131226	U S BANK - FORMERLY FIRSTAR
131227	U S BANK - FORMERLY FIRSTAR
131229	CUMBERLAND VALLEY NATIONAL
131230	FIRST STATE BANK
131231	BANK OF HARLAN
131232	CITIZENS NATIONAL BANK
131233	FIRST BANK & TRUST
131234	LEE BANK AND TRUST CO
131235	BANK OF AMERICA (BANK DRAFTS)
134007	RESTRICTED CASH - SHORT TERM

Account	Account Description
134011	CLOSED 05/11 - RESTRICTED CASH - SHORT TERM
134012	OTHER SPECIAL FUNDS MARGIN ACCOUNT
134025	CLOSED 11/11 - RESTRICTED CASH - MUSEUM PLAZA SHORT TERM
135001	WORKING FUNDS
136005	TEMP INV-OTHER
136015	TEMP INV-MONEY POOL-GOLDMAN SACHS <3 MOS
136016	TEMP INV-GOLDMAN SACHS-CASH UNRESTRICTED
136017	TEMP INV-BANK OF AMERICA-CASH UNRESTRICTED
136018	TEMP INV-FIDELITY INVESTMENTS-CASH UNRESTRICTED
136019	TEMP INV-JPMORGAN-CASH UNRESTRICTED
136020	TEMP INV-UBS-CASH UNRESTRICTED
141004	NOTES RECEIVABLE - INDUSTRIAL AUTHORITY
141005	RESERVE FOR NOTES RECEIVABLE - INDUSTRIAL AUTHORITY
142001	CUST A/R-ACTIVE
142002	A/R - UNPOSTEC CASH
142003	WHOLESALE SALES A/R
142004	TRANSMISSION RECEIVABLE
142008	CLOSED 07/11 - WHOLESALE SALES ACCOUNTS RECEIVABLE-UNBILLED
142999	CUST A/R KU SUSP CIS- ACCT'G USE ONLY
143001	A/R-OFFICERS/EMPL
143003	ACCTS REC - IMEA
143004	ACCTS REC - IMPA
143006	ACCTS REC - BILLED PROJECTS
143007	ACCTS REC - NON PROJECT UTIL ACCT USE ONLY
143011	INSURANCE CLAIMS
143012	ACCTS REC - MISCELLANEOUS
143017	ACCTS REC - DAMAGE CLAIMS (DTS)
143022	ACCTS REC - BEYOND THE METER
143024	A/R MUTUAL AID
143025	ACCT. RECEIVABLE - EL SWAPS
143027	INCOME TAX RECEIVABLE - FEDERAL
143028	INCOME TAX RECEIVABLE - STATE
143029	CLOSED 11/11 - EMPLOYEE COMPUTER LOANS
143030	EMPLOYEE PAYROLL ADVANCES
143031	ACCTS REC - RAR SETTLEMENTS
143032	ACCTS REC - TAX REFUNDS
143033	DEFAULT EMPLOYEE RECEIVABLES
143034	CLOSED 04/12 - A/R MISC - ENERGY MARKETING TRANSACTIONS
143035	A/R - EUSIC/EON
143036	SUSPENSE - PPL
143040	ACCTS REC - WKE UNWIND - DISPATCH, IT ADHOC, & CENTURY
143041	COBRA/LTD BENEFITS - RECEIVABLE
143052	ACCOUNTS RECEIVABLE - IMEA/IMPA OFFSET
143053	BECHTEL RECEIVABLE LIQUIDATED
143112	CLOSED 04/12 - A/R - MF GLOBAL MARGIN CASH COLLATERAL
144001	UNCOLL ACCT-CR-UTIL
144002	UNCOLL ACCT-DR-C/OFF
144003	UNCOLL ACCT-CR-RECOV
144004	UNCOLL ACCT-CR-OTHER
144006	UNCOLL ACCT-A/R MISC
144009	UNCOLL ACCTS - LEM
144014	UNCOLL A/R - WKE RESERVES
144015	UNCOLL A/R - BECHTEL RESERVE
144016	UNCOLL A/R - CENTURY INTEREST
144017	UNCOLL A/R - MF GLOBAL
145006	NOTES RECEIVABLE FROM LEM
145010	NOTES RECEIVABLE FROM LCC
145011	N/R - MONEY POOL - LGE
145012	N/R - MONEY POOL - KU
145013	N/R - MONEY POOL - LCC
145014	N/R - MONEY POOL - LPI
145015	N/R - MONEY POOL - LEM
145020	NOTES RECEIVABLE FROM LKE - CURRENT
145021	NOTES RECEIVABLE - PPL ENERGY FUNDING - CURRENT
145025	NOTES RECEIVABLE FROM LG&E AND KU ENERGY LLC NON-CURRENT
145026	NOTES RECEIVABLE FROM LEM-NON CURRENT
145030	NOTES RECEIVABLE FROM ECC - NON CURRENT
145100	N/R MONEY POOL - LG&E AND KU ENERGY LLC
146019	CLOSED 05/11 - A/R FROM EUSIC
146040	CLOSED 05/11 - I/C WITH ARGENTINA I
146048	INTERCOMPANY DIVIDENDS RECEIVABLE FROM LG&E COMPANY

Account	Account Description
146049	INTERCOMPANY ADVANCE FROM LG&E
146050	INTERCOMPANY ADVANCE FROM KU
146052	CLOSED 05/11 - A/R FROM E.ON ESPANA
146053	INTERCOMPANY PENSION RECEIVABLE
146054	I/C RECEIVABLE - PPL - MUTUAL ASSISTANCE
146055	I/C INTEREST RECEIVABLE - PPL ENERGY FUNDING CURRENT
146056	INTERCOMPANY DIVIDENDS RECEIVABLE FROM KU COMPANY
146057	I/C RECEIVABLE - PPL LEASE OF SIMPSONVILLE DATA CTR SPACE
146100	INTERCOMPANY
151010	FUEL STK-LEASED CARS
151020	COAL PURCHASES - TONS
151021	COAL - BTU ADJ - BTU
151022	COAL FINES - CONSIGNED INVENTORY
151023	IN-TRANSIT COAL
151024	COAL - CONSIGNED INVENTORY
151025	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - COAL PURCHAES
151026	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - COAL PURCHASES (STAT ONLY)
151030	FUEL OIL - GAL
151031	FUEL OIL - BTU
151032	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - FUEL OIL
151033	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - FUEL OIL (STAT ONLY)
151060	RAILCARS-OPER/MTCE
151061	GAS PIPELINE OPER/MTCE
151070	PETROL COKE-TEM STOR - TONS
151071	PETROL COKE-TEM STOR - BTU
151073	IN-TRANSIT COAL-MMBTU/IN-TRANSIT PET COKE <AUG 2009
151080	COAL BARGE SHUTTLING
151090	CLOSED 11/11 - PROPANE
154001	MATERIALS/SUPPLIES
154003	LIMESTONE
154004	COMMERCIAL LIME
154006	OTHER REAGENTS
154007	TC NON-JURISDICTIONAL CONTRA (IMEA/IMPA) - LIMESTONE
154008	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - M&S
154023	LIMESTONE IN-TRANSIT
158121	SO2 ALLOWANCE INVENTORY
158122	NOX OZONE SEASON ALLOWANCE INVENTORY
158124	SO2 ALLOWANCE INVENTORY-FUTURE VINTAGE (LT)
158125	NOX ANNUAL ALLOWANCE INVENTORY
158126	NOX OZONE SEASON ALLOWANCE INVENTORY - FUTURE VINTAGE (LT)
158127	NOX ANNUAL ALLOWANCE INVENTORY - FUTURE VINTAGE (LT)
163001	STORES EXPENSE
163002	WAREHOUSE EXPENSES
163003	FREIGHT
163004	ASSET RECOVERY
163005	SALES TAX
163006	PHYS INVENT ADJUSTMT
163007	INVOICE PRICE VARIANCES
163100	OTHER
163201	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - STORES
164101	GAS STORED-CURRENT
165001	PREPAID INSURANCE
165002	PREPAID TAXES
165006	PREPAID GAS FRANCH
165012	PREPAID LEASE
165013	PREPAID RIGHTS OF WAY
165018	PREPAID RISK MGMT AND WC
165020	PREPAID VEHICLE LICENSE
165100	PREPAID OTHER
165101	PREPAID IT CONTRACTS
165102	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - PREPAID
171001	INTEREST RECEIVABLE
171003	DIVIDENDS RECEIVABLE-EXTERNAL
172001	RENTS RECEIVABLE
173001	ACCRUED UTIL REVENUE
173005	ACCRUED WHOLESALE SALES REVENUE - UNBILLED
174001	MISC CURR/ACCR ASSET
175001	CLOSED 04/12 - DERIVATIVE ASSET - NONHEDGING-CURRENT
175501	CLOSED 04/12 - DERIVATIVE ASSET-NON-HEDGING-LONG-TERM
176002	DERIVATIVE ASSET - FV HEDGING - CURRENT
181004	UNAM EXP-PCB CC2007A $17.8M 02/26

Account	Account Description
181005	UNAM EXP-PCB TC2007A $8.9M 03/37
181008	UNAM EXP-KU REVOLVING CREDIT $400M 12/14
181009	UNAM EXP-FMB KU2010 $250M 11/15
181010	UNAM EXP-FMB KU2010 $500M 11/20
181011	UNAM EXP-FMB KU2010 $750M 11/40
181013	UNAM EXP-KU LETTER OF CREDIT FACILITY $198.309M 4/14
181016	UNAM EXP-SR NOTE LKE2010 $400M 11/15
181017	UNAM EXP-SR NOTE LKE2010 $475M 11/20
181018	UNAM EXP-SR NOTE LKE2011 $250M 9/21
181019	UNAM EXP-LGE REVOLVING CREDIT $400M 12/14
181020	UNAM EXP-FMB LGE2010 $250M 11/15
181021	UNAM EXP-FMB LGE2010 $285M 11/40
181050	UNAM DEBT EXPENSE
181103	UNAM EXP-PCB CC2008A $77.9M 02/32
181119	UNAM EXP-PCB JC2001A $10.1M 9/27
181126	UNAM EXP $35.2M 6/33
181127	UNAM EXP-PCB TC2007A $60M 6/33
181129	UNAM EXP-PCB TC2000A $83M 8/30
181180	UNAM EXP-PCB JC2001A $22.5M 9/26
181181	UNAM EXP-PCB TC2001A $27.5M 9/26
181182	UNAM EXP-PCB JC2001B $35M 11/27
181183	UNAM EXP-PCB TC2001B $35M 11/27
181184	UNAM EXP-PCB CC2002A $20.93M 2/32
181185	UNAM EXP-PCB CC2002B $2.4M 2/32
181186	UNAM EXP-PCB MERC2002A $7.4M 2/32
181187	UNAM EXP-PCB MUHC2002A $2.4M 2/32
181188	UNAM EXP-PCB CC2002C $96M 10/32
181189	UNAM EXP-PCB TC2002A $41.665M 10/32
181190	UNAM EXP-PCB JC2003A $128
181199	UNAM EXP-PCB CC2006B $54M 10/34
182305	REGULATORY ASSET - FAS 158 OPEB
182306	FUEL ADJUSTMENT CLAUSE
182307	ENVIRONMENTAL COST RECOVERY - GROUP 1
182308	REG ASSET - GAS SUPPLY CLAUSE
182309	VA FUEL COMPONENT
182311	FERC JURISDICTIONAL PENSION EXPENSE
182314	OTHER REGULATORY ASSETS
182315	REGULATORY ASSET - FAS 158 PENSION
182317	OTHER REGULATORY ASSETS ARO - GENERATION
182318	OTHER REG ASSETS ARO - TRANSMISSION
182319	CLOSED 11/11 - MILL CREEK ASH POND
182320	WINTER STORM - ELECTRIC
182321	MISO EXIT FEE
182322	RATE CASE EXPENSES - ELECTRIC - PRE-PPL MERGER CURRENT PORTION
182323	RATE CASE EXPENSES - GAS - PRE-PPL MERGER CURRENT PORTION
182324	EKPC FERC TRANSMISSION COST - KY PORTION - PRE-PPL MERGER CURRENT PORTION
182325	OTHER REGULATORY ASSETS ARO - DISTRIBUTION
182326	OTHER REGULATORY ASSETS ARO - GAS
182327	OTHER REGULATORY ASSETS ARO - COMMON
182328	FASB 109 ADJ-FED
182329	FASB 109 GR-UP-FED
182330	FASB 109 ADJ-STATE
182331	FASB 109 GR-UP-STATE
182332	CMRG FUNDING (CARBON MGT RESEARCH GROUP)
182333	KCCS FUNDING (KY CONSORTIUM FOR CARBON STORAGE)
182334	WIND STORM REGULATORY ASSET
182335	RATE CASE EXPENSES - ELECTRIC
182336	RATE CASE EXPENSES - GAS
182337	EKPC FERC TRANSMISSION COSTS - KY PORTION
182339	MOUNTAIN STORM - ELECTRIC
182340	REG ASSET - PERFORMANCE-BASED RATES
182342	WINTER STORM - GAS
182343	ASSET - SWAP TERMINATION - PRE-PPL MERGER CURRENT PORTION
182344	REG ASSET - LT - SWAP TERMINATION
182345	WINTER STORM - ELECTRIC - PRE-PPL MERGER CURRENT PORTION
182346	WINTER STORM - GAS - PRE-PPL MERGER CURRENT PORTION
182347	WIND STORM - ELECTRIC - PRE-PPL MERGER CURRENT PORTION
182348	CMRG FUNDING - PRE-PPL MERGER CURRENT PORTION
182349	KCCS FUNDING - PRE-PPL MERGER CURRENT PORTION
182352	REG ASSET - LT INTEREST RATE SWAP
182353	REG. ASSET - COAL CONTRACT - ST

Account	Account Description
182354	REG. ASSET - COAL CONTRACT
182355	REG. ASSET - LEASE
182356	REG ASSET - VA FUEL COMPONENT NON-CURRENT
182357	CLOSED 04/11 - PENSION & FAS106 PAA SERVCO ALLOCATION
182358	REG ASSET - UNAMORT DEBT EXP PAA
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC
182360	GENERAL MANAGEMENT AUDIT - GAS
182361	2011 SUMMER STORM - ELECTRIC
182362	ENVIRONMENTAL COST RECOVERY - GROUP 2
183201	OTH PREL SUR/INV-GAS
183301	PRELIM SURV/INV-ELEC
183302	PRELIMINARY SURV/INV ELEC - LT
184001	VACATION - BURDEN CLEARING
184002	VACATION PAY
184010	HOLIDAY - BURDEN CLEARING
184011	HOLIDAY PAY
184020	SICK - BURDEN CLEARING
184021	SICK PAY
184030	OTHER OFF-DUTY - BURDEN CLEARING
184031	OTHER OFF-DUTY PAY
184040	TEAM INCENTIVE AWARD - BURDEN CLEARING
184075	WORKERS COMP - BURDEN CLEARING
184076	ADMINISTRATIVE AND GENERAL - BURDEN CLEARING
184093	LONG TERM DISABILITY - BURDEN CLEARING
184096	PENSIONS - BURDEN CLEARING
184097	FASB 106 (OPEB) - BURDEN CLEARING
184098	FASB 112 (OPEB) - BURDEN CLEARING
184101	GROUP LIFE INSURANCE - BURDEN CLEARING
184104	DENTAL INSURANCE - BURDEN CLEARING
184105	MEDICAL INSURANCE - BURDEN CLEARING
184108	401K - BURDEN CLEARING
184109	RETIREMENT INCOME - BURDEN CLEARING
184119	CLOSED 04/11 - PENSION INTEREST - BURDEN CLEARING
184120	CLOSED 04/11 - FASB 106 INTEREST (OPEB) - BURDEN CLEARING
184121	OTHER BENEFITS - BURDEN CLEARING
184150	SYSTEM ALLOC-CO 1
184301	GASOLINE-TRANSP
184304	VEHICLE REPR-TRANSP
184307	ADMIN/OTH EXP-TRANSP
184308	VALUE-ADD SVCSTR
184309	DIESEL FUEL-TRANSP
184312	RENT/STORAGE-TRANSP
184313	TELECOM VEHICLE RADIO / COMPUTER EXPENSES
184314	LICENSE/TAX-TRANSP
184315	DEPRECIATION-TRANSP
184318	CLOSED 06/11 - TRANSPORTATION CLEARING ACCOUNT ADJUSTMENT
184319	FUEL ADMINISTRATION VEHICLES
184320	TRANSPORTATION EXPENSE ALLOCATION - CLEARING
184450	CL ACC TO OTH DEF CR
184500	OPR-DIST/ST BLDG-7TH
184501	MTCE-DIST/ST BLDG-7T
184504	OPERATION-SSC
184505	MAINTENANCE-SSC
184510	MTCE-WATERSIDE STRUC
184511	MISC SERV-WATERSIDE
184514	OPERATION-ESC
184515	MAINTENANCE-ESC
184516	OPERATION-BOC
184517	MAINTENANCE-BOC
184518	OPERATION-AUBURNDALE
184519	MAINT-AUBURNDALE
184520	MISC FAC O/M-OFFSET
184600	ENGINEERING OVERHEADS - GENERATION
184602	ENGINEERING OVERHEADS - DISTRIBUTION
184603	ENGINEERING OVERHEADS - RETAIL GAS
184605	ENGINEERING OVERHEADS - TRANSMISSION
184612	ENGINEERING OVERHEADS - DISTRIBUTION
184650	CUSTOMER ADVANCES - CLEARING
184701	EMPLOYEE ADVANCES - CLEARING
184702	IEXPENSE CREDIT CARD CLEARING
186001	MISC DEFERRED DEBITS

Account	Account Description
186004	FINANCING EXPENSE
186019	CLOSED 05/11 - LONG-TERM DERIVATIVE ASSET (FAS 133)
186035	KEY MAN LIFE INSURANCE
186049	PRELIMINARY CELL SITE COSTS
186082	CLOSED 04/11 - LT DERIVATIVE ASSET FAS 133 MS1
186083	CLOSED 04/11 - LT DERIVATIVE ASSET FAS 133 MS2
186084	CLOSED 04/11 - LT DERIVATIVE ASSET FAS 133 BOA
186505	GOODWILL
186548	OTHER INTANGIBLE ASSETS - SHORT TERM
186549	OTHER INTANGIBLE ASSETS
186553	OTH INTANG ASSETS - OVEC PPA ENERGY CONTRACT
186556	OTH INTANG ASSETS - SO2 ALLOWANCES - CURRENT
186557	OTH INTANG ASSETS - NOX OZONE ALLOWANCES - CURRENT
186558	OTH INTANG ASSETS - NOX ANNUAL ALLOWANCES - CURRENT
186559	OTH INTANG ASSETS - SO2 ALLOWANCES - FUTURE
186560	OTH INTANG ASSETS - NOX OZONE ALLOWANCES - FUTURE
186561	OTH INTANG ASSETS - NOX ANNUAL ALLOWANCES - FUTURE
186576	CARROLLTON SALE/LEASEBACK
189004	UNAM LOSS-1985J $25M 07/95
189007	UNAM LOSS-FMB $25M 10/09
189008	UNAM LOSS-1976B $35.2M 09/06
189009	UNAM LOSS-1975A $31M 09/00
189010	UNAM LOSS-1987A $60M 08/97
189024	UNAM LOSS-PCB JC1990A $25M 06/15
189025	UNAM LOSS-PCB TC1990A $83.3M 11/20
189030	UNAM LOSS-PCB JC1992A $31M 09/17
189031	UNAM LOSS-PCB JC1993A $35.2M 08/13
189034	UNAM LOSS-FMB Series R 06/25
189035	UNAM LOSS-PCB TC1992A $60M 09/17
189042	UNAM LOSS-PCB MERC2000A $12.9M 05/23
189050	UNAM DEBT LOSS
189080	UNAM LOSS-PCB JC1996A $22.5M 09/26
189081	UNAM LOSS-PCB TC1996A $27.5M 09/26
189082	UNAM LOSS-PCB JC1997A $35M 11/27
189083	UNAM LOSS-PCB TC1997A $35M 11/27
189084	UNAM LOSS-PCB CC2002A $20.93M 2/32
189085	UNAM LOSS-PCB CC2002B $2.4M 2/32
189086	UNAM LOSS-PCB MERC2002A $7.4M 2/32
189087	UNAM LOSS-PCB MUHC2002A $2.4M 2/32
189088	UNAM LOSS-PCB CC2002C $96M 10/32
189089	UNAM LOSS-TC1990B $41.665M 10/20
189090	UNAM LOSS-JC1993B $26M 11/03
189091	UNAM LOSS-FMB Series P $33M 05/15
189092	UNAM LOSS-PCB CC2004A $50M 10/34
189093	UNAM LOSS-PCB $7.2M REDEEMED
189094	UNAM LOSS-JC1995A $40M 11/05
189096	UNAM LOSS-PCB CC1994A $54M 11/24
189098	UNAM LOSS-PCB CC2006C $16.7M 05/36
189125	UNAM LOSS-PCB LM/JC2007A $31M 06/33
189126	UNAM LOSS-PCB LM/JC2007B $35.2M 06/33
189128	UNAM LOSS-PCB JC2000A $25M 05/27
189190	UNAM LOSS-LM/JC2003A $128M 10/33
189194	UNAM LOSS-PCB LM/JC2005A $40M 02/35
189195	UNAM LOSS-PCB CC2005A $13M 06/35
189196	UNAM LOSS-PCB CC2005B $13M 06/35
189197	UNAM LOSS-PCB CC2006A $17M 06/36
190001	CLOSED 12/11 - ACC DEF INC TAX-FED
190002	CLOSED 12/11 - ACC DEF INC TAX CURRENT-FED
190003	CLOSED 12/11 - ACC DEF INC TAX-ST
190004	CLOSED 12/11 - ACC DEF INC TAX CURRENT - STATE
190007	FASB 109 ADJ-FED
190008	FASB 109 GRS-UP-FED
190009	FASB 109 ADJ-STATE
190010	FASB 109 GRS-UP-ST
190307	CLOSED 12/11 - DTA ON INVENTORIES
190308	CLOSED 12/11 - DTA ON RECEIV. AND OTHER ASSETS (NON DERIV.)
190311	CLOSED 12/11 - DTA ON OTHER REC. FR. DERIV. - CURRENT
190315	DTA ON PROVISIONS FOR PENSIONS AND SIMILAR OBLIGATIONS
190318	DTA ON LIABILITIES (EXCLUDING DERIVATIVES)
190322	DTA ON LOSSES CARRIED FORWARD
190324	DTA ON VALUATION ALLOWANCE - FED-CURRENT

Account	Account Description
190361	CLOSED 05/11 - NETTING OUT DEFERRED TAX ASSETS - A
190362	CLOSED 05/11 - NETTING OUT DEFERRED TAX ASSETS - B
190403	DTA ON FIXED ASSETS
190405	CLOSED 12/11 - DTA ON SHARES IN ASSOC. COMPANIES AND OTHER SHAREHOLDINGS
190408	CLOSED 12/11 - DTA ON RECEIV. AND OTHER ASSETS (NON DERIV.)
190410	CLOSED 12/11 - DTA ON OTHER RECEIVABLES FR. DERIV. FINANCIAL INSTRUMENTS
190411	CLOSED 12/11 - DTA ON OTHER REC. FR. DERIV. - NON-CURRENT
190414	DTA ON PROVISIONS FOR PENSIONS - OCI - FED (NON-CURRENT)
190415	DTA ON PROVISIONS FOR PENSIONS AND SIMILAR OBLIGATIONS
190418	DTA ON LIABILITIES (EXCLUDING DERIVATIVES)
190422	DTA ON LOSSES CARRIED FORWARD
190423	DTA ON TAX CREDITS
190424	DTA ON VALUATION ALLOWANCE
190426	CLOSED 12/11 - DTA AS RESULT OF SPECIFIC FOREIGN COUNTRY ITEMS
190461	CLOSED 05/11 - NETTING OUT DEFERRED TAX ASSETS - C
190462	CLOSED 05/11 - NETTING OUT DEFERRED TAX ASSETS - D
190507	CLOSED 12/11 - DTA ON INVENTORIES - STATE
190508	CLOSED 12/11 - DTA ON RECEIV. AND OTHER ASSETS (NON DERIV.) - STATE
190511	CLOSED 12/11 - DTA ON OTHER REC. FR. DERIV. - STATE - CURRENT
190515	DTA ON PROVISIONS FOR PENSIONS AND SIMILAR OBLIGATIONS - STATE
190518	DTA ON LIABILITIES (EXCLUDING DERIVATIVES) - STATE
190522	DTA ON LOSSES CARRIED FORWARD -STATE
190524	DTA ON VALUATION ALLOWANCE - ST-CURRENT
190561	CLOSED 05/11 - NETTING OUT DEFERRED TAX ASSETS - STATE - A
190562	CLOSED 05/11 - NETTING OUT DEFERRED TAX ASSETS - STATE - B
190603	DTA ON FIXED ASSETS - STATE (NON-CURRENT)
190605	CLOSED 12/11 - DTA ON SHARES IN ASSOC. COMPANIES AND OTHER SHAREHOLDINGS - STATE (NON-CURRENT)
190608	CLOSED 12/11 - DTA ON RECEIV. AND OTHER ASSETS (NON DERIV.) - STATE (NON-CURRENT)
190610	CLOSED 12/11 - DTA ON OTHER RECEIVABLES FR. DERIV. FINANCIAL INSTRUMENTS - STATE (NON-CURRENT)
190611	CLOSED 12/11 - DTA ON OTHER REC. FR. DERIV. - STATE - NON-CURRENT
190614	DTA ON PROVISIONS FOR PENSIONS - OCI - ST (NON-CURRENT)
190615	DTA ON PROVISIONS FOR PENSIONS AND SIMILAR OBLIGATIONS - STATE (NON-CURRENT)
190618	DTA ON LIABILITIES (EXCLUDING DERIVATIVES) - STATE (NON-CURRENT)
190622	DTA ON LOSSES CARRIED FORWARD -STATE (NON-CURRENT)
190623	DTA ON TAX CREDITS - STATE (NON-CURRENT)
190624	DTA ON VALUATION ALLOWANCE - STATE (NON-CURRENT)
190626	CLOSED 12/11 - DTA AS RESULT OF SPECIFIC FOREIGN COUNTRY ITEMS - STATE (NON-CURRENT)
190661	CLOSED 05/11 - NETTING OUT DEFERRED TAX ASSETS - STATE - C
190662	CLOSED 05/11 - NETTING OUT DEFERRED TAX ASSETS - STATE - D
201001	COMMON STOCK-AUTH SH
201002	COMMON STOCK-W/O PAR
211001	CONTRIBUTED CAPITAL - MISC.
211004	PAA PCB CC2007A $17.8M 02/26 5.75%
211005	PAA PCB TC2007A $8.9M 03/37 6.00%
211122	PAA ON EEI INVESTMENT
211123	PAA ON OVEC INVESTMENT
211125	PAA PCB LM/JC2007A $31M 06/33 5.625%
211127	PAA PCB TC2007A $60M 06/33 4.6%
211128	PAA PCB JC2000A $25M 05/27 5.375%
211194	PAA PCB LM/JC2005A $40M 02/35 5.750%
214010	CAP STOCK EXP-COMMON
216001	UNAPP RETAINED EARN
216101	UNAPP UNDST SUB EARN
219001	CLOSED 06/11 - OCI - CUM EFFECT OF CHANGE - INT SWAPS
219002	CLOSED 06/11 - OCI - INT SWAPS
219010	ACCUM OCI - EQUITY INVEST EEI
219011	ACCUM OCI OF SUBS - PTAX
219013	OCI - FAS 158 INCREASE FUNDED STATUS - GROSS
219101	TAX OCI-CUM EFFECT OF CHANGE-INT SWAPS
219102	TAX OCI-INT SWAPS
219110	DEFERRED TAX - OCI - EQUITY INVEST EEI
219111	ACCUM OCI OF SUBS - TAX
219113	OCI - FAS 158 INCREASE FUNDED STATUS - TAX
221004	PCB CC2007A $17.8M 02/26 5.75%
221005	PCB TC2007A $8.9M 03/37 6.00%
221009	FMB KU2010 $250M 11/15 1.625%
221010	FMB KU2010 $500M 11/20 3.250%
221011	FMB KU2010 $750M 11/40 5.125%
221016	SR NOTE LKE2010 $400M 11/15 2.125%
221017	SR NOTE LKE2010 $475M 11/20 3.750%
221018	SR NOTE LKE2011 $250M 9/21

Account	Account Description
221020	FMB LGE2010 $250M 11/15 1.625%
221021	FMB LGE2010 $285M 11/40 5.125%
221025	$31 MILLION BOND DUE 6/33 - REPURCHASED
221026	PCB LM/JC2007B $35.2M 06/33 VAR
221028	PCB SER 00A 5/2027 - REPURCHASED
221046	PCB MERC2000A $12.9M 05/23 VAR
221090	PCB LM/JC2003A $128M 10/33 VAR
221092	PCB CC2004A $50M 10/34 VAR
221094	PCB JC2005A $40M DUE 2/35 - REPURCHASED
221125	PCB LM/JC2007A $31M 06/33 5.625%
221126	$35.2 MILLION BOND DUE 6/33
221127	PCB TC2007A $60M 06/33 4.6%
221128	PCB JC2000A $25M 05/27 5.375%
221129	PCB TC2000A $83.3M 08/30 VAR
221130	PCB JC2001A $10.1M 09/27 VAR
221188	PCB CC2002C $96M 10/32 VAR
221189	PCB TC2002A $41.665M 10/32 VAR
221190	PCB JC2003A $128M 10/33 V
221194	PCB LM/JC2005A $40M 02/35 5.750%
221280	PCB JC2001A $22.5M 09/26 VAR
221281	PCB TC2001A $27.5M 09/26 VAR
221282	PCB JC2001B $35M 11/27 VAR
221283	PCB TC2001B $35M 11/27 VAR
221284	PCB CC2002A $20.93M 02/32 VAR
221285	PCB CC2002B $2.4M 02/32 VAR
221286	PCB MERC2002A $7.4M 02/32 VAR
221287	PCB MUHC2002A $2.4M 02/32 VAR
221299	PCB CC2006B $54M 10/34 VAR
221303	PCB CC2008A $77.9M 02/32 VAR
222096	PCB LM/JC2007B $35.2M 06/33 VAR-REACQUIRED
222190	PCB LM/JC2003A $128M 10/33 VAR-REACQUIRED
223002	CLOSED 04/11 - L-T DEBT PAYABLE TO FIDELIA/PPL (EFF 11/10)
223004	CLOSED 04/11 - L-T ADVANCES PAYABLE FROM E.ON NA/PPL (EFF 11/10)
223005	LT NOTES PAYABLE TO E.ON U.S.
223006	LT NOTES PAYABLE TO LG&E AND KU CAPITAL LLC
223014	LT NOTES PAYABLE TO SERVCO
223015	LT NOTES PAYABLE TO LEM
224004	PAA PCB CC2007A $17.8M 02/26 5.75%
224005	PAA PCB TC2007A $8.9M 03/37 6.00%
224125	PAA PCB LM/JC2007A $31M 06/33 5.625%
224127	PAA PCB TC2007A $60M 06/33 4.6%
224128	PAA PCB JC2000A $25M 05/27 5.375%
224194	PAA PCB LM/JC2005A $40M 02/35 5.750%
226009	DEBT DISC-FMB KU2010 $250M 11/15
226010	DEBT DISC-FMB KU2010 $500M 11/20
226011	DEBT DISC-FMB KU2010 $750M 11/40
226016	DEBT DISC-SR NOTE LKE2010 $400M 11/15
226017	DEBT DISC-SR NOTE LKE2010 $475M 11/20
226018	DEBT DISC-SR NOTE LKE2011 $250M 9/21
226020	DEBT DISC-FMB LGE2010 $250M 11/15
226021	DEBT DISC-FMB LGE2010 $285M 11/40
228201	WORKERS COMPENSATION
228202	WORKERS COMPENSATION - SHORT-TERM
228301	FASB106-POST RET BEN
228304	PENSION PAYABLE
228305	POST EMPLOYMENT BENEFIT PAYABLE
228306	PENSION PAYABLE SERP
228307	FASB 106 - MEDICARE SUBSIDY
228308	PENSION PAYABLE - SERP - NON-MERCER
228318	PENSION PAYABLE - SERP - NON-MERCER - CURRENT
228325	FASB 112 - POST EMPLOY MEDICARE SUBSIDY
230012	ASSET RETIREMENT OBLIGATIONS - STEAM
230013	ASSET RETIREMENT OBLIGATIONS - TRANSMISSION
230015	ASSET RETIREMENT OBLIGATIONS - DISTRIBUTION
230016	ASSET RETIREMENT OBLIGATIONS - GAS
230017	ASSET RETIREMENT OBLIGATIONS - COMMON
230022	ASSET RETIREMENT OBLIGATIONS - STEAM - ST
230023	ASSET RETIREMENT OBLIGATIONS - TRANSMISSION - ST
230025	ASSET RETIREMENT OBLIGATIONS - DISTRIBUTION - ST
230026	ASSET RETIREMENT OBLIGATIONS - GAS - ST
230027	ASSET RETIREMENT OBLIGATIONS - COMMON - ST

Account	Account Description
231005	COMMERCIAL PAPER PAYABLE
231006	DISCOUNT ON COMMERCIAL PAPER
231008	ST-NP KU REVOLVING CREDIT $400M 12/14
231019	ST-NP LGE REVOLVING CREDIT $400M 12/14
231501	CLOSED 11/11 - MEDIUM TERM NOTES
231503	CLOSED 11/11 - MEDIUM TERM NOTES-CURRENT
232001	ACCTS PAYABLE-REG
232002	SALS/WAGES ACCRUED
232008	SUNDRY BILLING REFUNDS
232009	PURCHASING ACCRUAL
232010	WHOLESALE PURCHASES A/P
232011	TRANSMISSION PAYABLE
232014	RECEIVING/INSPECTION ACCRUAL
232015	AP FUEL
232022	ACCRUED AUDIT FEES
232023	ACCRUED TAXABLE OFFICER BENEFITS
232024	CREDIT CASH BALANCE
232030	RETAINAGE FEES
232040	ACCTS PAY - WKE UNWIND - COST OF IT SERVICE AGREEMENT
232042	MISO AND PJM ANCILLARY SERVICES CHARGES A/P
232050	ACCTS PAYABLE - EON
232093	SUSPENSE - CCS
232095	SUSPENSE - SALES TAX BURDEN
232096	SUSPENSE - OTHER BURDENS
232097	SUSPENSE - INVENTORY
232098	SUSPENSE - MANUAL DISABLED
232099	SUSPENSE ACCOUNT
232100	ACCOUNTS PAYABLE-TRADE
232111	401K LIABILITY - EMPLOYER
232203	WORK SHOES WITHHOLDING PAYABLE
232205	IBEW UNION DUES WITHHOLDING PAYABLE
232206	UNITED WAY WITHHOLDING PAYABLE
232211	TIA LIABILITY
232219	FEDERAL PAC WITHHOLDING PAYABLE
232220	CREDIT UNION WITHHOLDING PAYABLE
232233	401K WITHHOLDING PAYABLE
232235	UNITED STEEL WORKERS UNION DUES
232243	LOUISVILLE PAC WITHHOLDING PAYABLE
232244	GARNISHEES WITHHOLDING PAYABLE
232245	CLOSED 04/11 - US SAVINGS BONDS WITHHOLDING PAYABLE
232246	DCAP WITHHOLDING PAYABLE
232248	HCRA WITHHOLDING PAYABLE
232249	UNIVERSAL LIFE INS WITHHOLDING PAYABLE
232503	A/P WKE (WKE PORTION)
232504	A/P WKE (CITY PORTION)
233008	CLOSED 04/11 - NOTES PAYABLE TO LG&E AND KU ENERGY LLC
233009	CLOSED 04/11 - NOTES PAYABLE TO LG&E AND KU CAPITAL CORP
233011	ST - NOTES PAYABLE TO E.ON NA/PPL (EFF 11/10)
233013	ST - NOTES PAYABLE TO SERVCO
233019	SHORT TERM NOTES PAYABLE TO LG&E AND KU CAPITAL CORP
233028	NOTES PAYABLE TO LG&E AND KU ENERGY LLC - CURRENT
233030	N/P - MONEY POOL LG&E AND KU ENERGY LLC CURRENT
233036	CLOSED 04/11 - N/P - MONEY POOL LPD CURRENT
233037	CLOSED 04/11 - N/P - MONEY POOL LPO CURRENT
234011	CLOSED 05/11 - I/C PAYABLE - POWERGEN US HOLDINGS
234012	I/C PAYABLE - EON N. AMERICA/PPL (EFF 11/10)
234017	CLOSED - KU
234019	CLOSED 05/11 - I/C PAYABLE - EUSIC
234051	INTERCOMPANY PENSION PAYABLE
234052	I/C PAYABLE - PPL
234053	I/C PAYABLE TO PPL ENERGY SUPPLY
234100	A/P TO ASSOC CO
235001	CUSTOMER DEPOSITS
235002	CUSTOMER DEPOSITS OFF-SYS
236007	FICA-OPR
236009	CLOSED 12/11 - AUTO/TRAILER LICENSE-OPR
236013	ST SALES/USE TAX-KY-OPR
236023	ST SALES/USE TAX-IN-OPR
236025	CORP INC TAX-FED EST-OPR
236026	CORP INC TAX-ST EST-OPR
236027	COAL TAX

Account	Account Description
236031	CORP INCOME-KY-OPR
236032	CORP INCOME-FED-OPR
236033	REAL ESTATE AND PERSONAL PROPERTY TAXES
236034	PROPERTY TAX ON RAILCARS USED FOR COAL
236035	OTHER TAXES ACCRUED-OPR
236036	REAL ESTATE AND PERSONAL PROPERTY TAXES - NON KY
236115	STATE UNEMPLOYMENT-OPR
236116	FEDERAL UNEMPLOYMENT-OPR
237004	ACCR INT-PCB CC2007A $17.8M 02/26
237005	ACCR INT-PCB TC2007A $8.9M 03/37
237007	ACCR INT-COMMERCIAL PAPER
237008	ACCR INT-KU REVOLVING CREDIT $400M 12/14
237009	ACCR INT-FMB KU2010 $250M 11/15
237010	ACCR INT-FMB KU2010 $500M 11/20
237011	ACCR INT-FMB KU2010 $750M 11/40
237016	ACCR INT-SR NOTE LKE2010 $400M 11/15
237017	ACCR INT-SR NOTE LKE2010 $475M 11/20
237018	ACCR INT-SR NOTE LKE2011 $250M 9/21
237019	ACCR INT-LGE REVOLVING CREDIT $400M 12/14
237020	ACCR INT-FMB LGE2010 $250M 11/15
237021	ACCR INT FMB LGE2010 $285M 11/40
237103	ACCR INT-PCB CC2008A $77.9M 02/32
237125	ACCR INT-PCB LM/JC2007A $31M 06/33
237126	ACCR INT-PCB LM/JC2007B $35.2M 06/33
237127	ACCR INT-PCB TC2007A $60M 06/33
237128	ACCR INT-PCB JC2000A $25M 05/27
237129	ACCR INT-PCB TC2000A $83.3M 08/30
237131	ACCR INT-PCB JC2001A $10.1M 09/27
237149	ACCR INT-PCB MERC2000A $12.9M 05/23
237161	ACCR INT-SWAP-JPM $83.335M 11/20 5.495%
237164	ACCR INT-SWAP-MS $32M 10/32 3.657%
237165	ACCR INT-SWAP-MS $32M 10/32 3.645%
237166	ACCR INT-SWAP-BOA $32M 10/32 3.695%
237180	ACCR INT-PCB JC2001A $22.5M 9/26
237181	ACCR INT-PCB TC2001A $27.5M 9/26
237182	ACCR INT-PCB JC2001B $35M 11/27
237183	ACCR INT-PCB TC2001B $35M 11/27
237184	ACCR INT-PCB CC2002A $20.93M 2/32
237185	ACCR INT-PCB CC2002B $2.4M 2/32
237186	ACCR INT-PCB MERC2002A $7.4M 2/32
237187	ACCR INT-PCB MUHC2002A $2.4M 2/32
237188	ACCR INT-PCB CC2002C $96M 10/32
237189	ACCR INT-PCB TC2002A $41.665M 10/32
237190	ACCR INT-PCB LM/JC2003A $128M 10/33
237192	ACCR INT-PCB CC2004A $50M 10/34
237194	ACCR INT-PCB LM/JC2005A $40M 2/35
237199	ACCR INT-PCB CC2006B $54M 10/34
237300	INT ACC-OTH LIAB
237301	INTEREST ACCRUED ON CUSTOMER DEPOSITS
237302	CLOSED 05/11 - INTEREST ACCRUED ON RAR SETTLEMENTS
237304	INTEREST ACCRUED ON TAX LIABILITIES
238200	DIV PAYABLE - PARENT FM LGE
238203	DIV PAYABLE - PARENT FM KU
238204	DIV PAYABLE - PPL FM LKE
241007	TAX COLL PAY-FICA
241018	STATE WITHHOLDING TAX PAYABLE
241036	LOCAL WITHHOLDING TAX PAYABLE
241037	T/C PAY-PERS INC-FED
241038	T/C PAY-ST SALES/USE
241039	T/C PAY-OCCUP/SCHOOL
241046	CONSUMER UTILITY TAX-VA
241047	SALES TAX-NORTON, VA
241048	CLOSED 08/11 - FRANCHISE FEE-NET UNBILLED
241049	FRANCHISE FEE PAYABLE-CHARGE UNCOLLECTED
241056	FRANCHISE FEE COLLECTED ON BAD DEBTS
241061	T/C PAY - ST SALES/USE OVER COLLECTIONS
241062	T/C PAY - SCHOOL TAX OVER COLLECTIONS
242001	MISC LIABILITY
242002	MISC LIAB-VESTED VAC
242003	CLOSED 06/11 - ACCRUED OFFICER LONG-TERM INCENTIVE-CURR PORTION
242005	UNEARNED REVENUE - CURRENT

Account	Account Description
242014	ESCHEATED DEPOSITS
242015	FRANCHISE FEE PAYABLE-FRANCHISE LOCATIONS
242017	HOME ENERGY ASSISTANCE
242018	GREEN POWER REC LIABILITY
242019	GREEN POWER MKT LIABILITY
242021	FASB 106-POST RET BEN - CURRENT
242022	ACCRUED SHORT TERM INCENTIVE
242023	PENSION PAYABLE SERP CURRENT
242026	PENSION PAYABLE - CURRENT
242028	SERVICE DEPOSIT REFUND PAYABLE
242030	WINTERCARE ENERGY FUND
242031	NO-NOTICE GAS PAYABLE
242034	MCI UNEARNED REVENUE
242035	DEFERRED REVENUE - COMMODITY SWAP MARGIN RECEIPTS
242038	COBRA/LTD BENEFITS - PAYABLE
242039	SUSPENSE - CASH
242101	RETIREMENT INCOME LIABILITY
244001	CLOSED 04/12 - DERIVATIVE LIABILITY - NONHEDGING-CURRENT
244501	CLOSED 04/12 - DERIVATIVE LIABILITY-NON-HEDGING-LONG-TERM
244512	LT DERIV LIAB FAS 133-NON HEDGING MS1
244513	LT DERIV LIAB FAS 133-NON HEDGING MS2
244514	LT DERIV LIAB FAS 133-NON HEDGING BOA
244515	ST DERIV LIAB FAS 133-NON HEDGING MS1
244516	ST DERIV LIAB FAS 133-NON HEDGING MS2
244517	ST DERIV LIAB FAS 133-NON HEDGING BOA
245501	LT DERIVATIVE LIAB FAS 133 JPM
245502	CLOSED 04/11 - LT DERIVATIVE LIAB FAS 133 MS1
245503	CLOSED 04/11 - LT DERIVATIVE LIAB FAS 133 MS2
245504	CLOSED 04/11 - LT DERIVATIVE LIAB FAS 133 BOA
245506	ST DERIV LIAB FAS 133 JPM
252009	CLOSED 11/11 - CUSTOMER ADVANCES - UNAPPLIED MUSEUM PLAZA CASH ADVANCE
252011	LINE EXTENSIONS
252012	20% SUPPLEMENT
252013	OTH CUST ADV-CONSTR
252014	CUST OUTDOOR LIGHTING DEPOSITS
252015	MOBILE HOME LINE
252016	CONSTRUCTION ADVANCES - SHORT TERM
252017	LINE EXTENSIONS - SHORT TERM
252018	CUST OUTDOOR LIGHTING DEP - SHORT TERM
252019	20% SUPPLEMENT - SHORT TERM
252101	CUSTOMER ADVANCES - PARTIAL PAYMENTS
253004	OTH DEFERRED CR-OTHR
253005	CL ACC FR OTH DEF DR
253006	CLOSED 06/11 - ACCRUED OFFICER LONG-TERM INCENTIVE
253025	DEFERRED COMPENSATION
253027	DEFERRED RENT PAYABLE
253028	OTHER DEFERRED CREDITS-CROSS BORDER LEASE
253031	OTHER LONG TERM OPERATING LIABILITIES
253032	UNCERTAIN TAX POSITION - FEDERAL
253033	UNCERTAIN TAX POSITION - STATE
253034	MCI AMORTIZATION
253036	CLOSED 04/12 - PENILE CITY TEXAS GAS CONSTR ADVANCE
253037	UNEARNED REVENUE - POLE ATTACHMENTS - LONG-TERM
253038	OTHER DEF. CREDIT - COAL CONTRACT - ST
253039	OTHER DEF. CREDIT - COAL CONTRACT - LT
253301	PROVISIONS FOR INDEMNITY OBLIGATIONS
253320	UNCERTAIN TAX POSITIONS - INTEREST
253576	DEF GAIN - CARROLLTON SALE/LEASEBACK
254001	FASB 109 ADJ-FED
254002	FASB 109 GR-UP-FED
254003	FASB 109 ADJ-STATE
254004	FASB 109 GR-UP-STATE
254006	REG LIAB - PURCHASED GAS ADJUSTMENT
254007	REG LIABILITY - GAS SUPPLY CLAUSE
254008	DSM COST RECOVERY
254009	REG LIABILITY - PERFORMANCE-BASED RATES
254010	REGULATORY LIABILITY - FAS 158 OPEB
254011	VIRGINIA FUEL COMPONENT
254012	SPARE PARTS
254014	REGULATORY LIABILITY ARO - GENERATION
254015	REGULATORY LIABILITY ARO - TRANSMISSION

Account	Account Description
254016	REGULATORY LIABILITY ARO - GAS
254017	ENVIRONMENTAL COST RECOVERY - GROUP 1
254018	REGULATORY LIABILITY FAC
254019	ENVIRONMENTAL COST RECOVERY - GROUP 2
254054	REG. LIABILITY - COAL CONTRACT - ST
254055	REG. LIABILITY - COAL CONTRACT - LT
254056	PAA REG LIABILITY - EMISSION ALLOWANCES - CURRENT
254057	PAA REG LIABILITY - EMISSION ALLOWANCES - LT
254058	PAA REGULATORY LIABILITY - OVEC VALUATION
254321	MISO EXIT FEE REFUND
254356	REG LIABILITY - VA FUEL COMPONENT NON-CURRENT
255004	ITC TC2
255005	ITC (PRIOR LAW)
255006	JOB DEVELOP CR
282001	CLOSED 12/11 - DEF INC TAX-PROP-FED
282003	CLOSED 12/11 - DEF INC TAX-PROP-ST
282007	FASB 109 ADJ-FED PRO
282009	FASB 109 ADJ-ST PROP
282503	DTL ON FIXED ASSETS
282703	DTL ON FIXED ASSETS - STATE (NON-CURRENT)
283001	CLOSED 12/11 - DEF INC TAX-OTH-FED
283002	CLOSED 12/11 - DEF INC TAX CURRENT-OTH-FED
283003	CLOSED 12/11 - DEF INC TAX-OTH-ST
283004	CLOSED 12/11 - DEF INC TAX CURRENT-OTH-STATE
283007	FASB 109 ADJ-FED
283008	FASB 109 GRS-UP-FED
283009	FASB 109 ADJ-STATE
283010	FASB 109 GRS-UP-ST
283011	FASB 109 GR-UP-F-OTH
283012	FASB 109 GR-UP-S-OTH
283017	DEF INC TAX - FED EST
283018	DEF INC TAX - ST EST
283408	CLOSED 12/11 - DTL ON RECEIVABLES AND OTHER ASSETS (NON DERIVATIVE)
283413	CLOSED 12/11 - DTL ON PREPAID EXPENSES
283418	DTL ON LIABILITIES (EXCLUDING DERIVATIVES)
283461	CLOSED 05/11 - NETTING OUT DEFERRED TAX LIABILITIES - A
283462	CLOSED 05/11 - NETTING OUT DEFERRED TAX LIABILITIES - B
283505	CLOSED 12/11 - DTL ON SHARES IN ASSOC. COMP. AND OTHER SHAREHOLDINGS
283506	CLOSED 12/11 - DTL ON OTHER FINANCIAL ASSETS (LOANS, SECUR., OTHER)
283508	CLOSED 12/11 - DTL ON RECEIVABLES AND OTHER ASSETS (NON DERIVATIVE)
283514	DTL ON PROVISIONS FOR PENSIONS - OCI - FED (NON-CURRENT)
283515	DTL ON PROVISIONS FOR PENSIONS AND SIMILAR OBLIGATIONS
283518	DTL ON LIABILITIES (EXCLUDING DERIVATIVES)
283519	DTL ON LIABILITIES - EEI -FED (NON-CURRENT)
283526	CLOSED 12/11 - DTL AS RESULT OF SPECIFIC FOREIGN COUNTRY ITEMS
283561	CLOSED 05/11 - NETTING OUT DEFERRED TAX LIABILITIES - C
283562	CLOSED 05/11 - NETTING OUT DEFERRED TAX LIABILITIES - D
283608	CLOSED 12/11 - DTL ON RECEIVABLES AND OTHER ASSETS (NON DERIVATIVE) - STATE
283613	CLOSED 12/11 - DTL ON PREPAID EXPENSES - STATE
283618	DTL ON LIABILITIES (EXCLUDING DERIVATIVES) - STATE
283661	CLOSED 05/11 - NETTING OUT DEFERRED TAX LIABILITIES - STATE - A
283662	CLOSED 05/11 - NETTING OUT DEFERRED TAX LIABILITIES - STATE - B
283705	CLOSED 12/11 - DTL ON SHARES IN ASSOC. COMP. AND OTHER SHAREHOLDINGS - STATE (NON-CURRENT)
283706	CLOSED 12/11 - DTL ON OTHER FINANCIAL ASSETS (LOANS, SECUR., OTHER) - STATE (NON-CURRENT)
283708	CLOSED 12/11 - DTL ON RECEIVABLES AND OTHER ASSETS (NON DERIVATIVE) - STATE (NON-CURRENT)
283714	DTL ON PROVISIONS FOR PENSIONS - OCI - STATE (NON-CURRENT)
283715	DTL ON PROVISIONS FOR PENSIONS AND SIMILAR OBLIGATIONS - STATE (NON-CURRENT)
283718	DTL ON LIABILITIES (EXCLUDING DERIVATIVES) - STATE (NON-CURRENT)
283719	DTL ON LIABILITIES - EEI - STATE (NON-CURRENT)
283726	CLOSED 12/11 - DTL AS RESULT OF SPECIFIC FOREIGN COUNTRY ITEMS - STATE (NON-CURRENT)
283761	CLOSED 05/11 - NETTING OUT DEFERRED TAX LIABILITIES - STATE - C
283762	CLOSED 05/11 - NETTING OUT DEFERRED TAX LIABILITIES - STATE - D
400001	SALES REVENUE - GENERAL
401001	COST OF SALES - GENERAL
401100	OPERATING EXPENSES
402100	MAINTENANCE EXPENSE
403011	DEPREC EXP - STEAM POWER GEN
403012	DEPREC EXP - HYDRO POWER GEN
403013	DEPREC EXP - OTH POWER GEN
403014	DEPREC EXP - TRANSMISSION
403015	DEPREC EXP - DISTRIBUTION

Account	Account Description
403016	GENERAL DEPRECIATION EXPENSE
403021	DEPREC. EXP. - UNDERGROUND - GAS
403022	DEPREC. EXP. - TRANSMISSION - GAS
403023	DEPREC. EXP. - DISTRIBUTION - GAS
403024	DEPREC. EXP. - GENERAL - GAS
403025	DEPREC. EXP. - COMMON
403026	DEPREC. EXP. - STEAM - ECR
403027	DEPREC EXP - ELECTRIC - DSM
403028	DEPREC EXP - GAS - DSM
403100	DEPREC EXP
403111	DEPREC EXP ARO STEAM
403112	DEPREC EXP ARO TRANSMISSION
403113	DEPREC EXP ARO OTHER PRODUCTION
403114	DEPREC EXP ARO HYDRO
403115	DEPREC EXP ARO DISTRIBUTION
403211	DEPREC EXP ARO GAS UNDERGROUND STORAGE
403212	DEPREC EXP ARO GAS DISTRIBUTION
403213	DEPREC EXP ARO GAS TRANSMISSION
403311	DEPREC EXP ARO COMMON
404301	AMORT-INTANG GAS PLT
404401	AMT-EL INTAN PLT-RTL
404402	AMT-EL INTAN PLT-WHS
407401	REGULATORY CREDITS - GENERATION ACCRETION
407402	REGULATORY CREDITS - TRANSMISSION ACCRETION
407405	REGULATORY CREDITS - DISTRIBUTION ACCRETION
407406	REGULATORY CREDITS - GAS ACCRETION
407407	REGULATORY CREDITS - COMMON ACCRETION
407421	REGULATORY CREDITS - GENERATION DEPRECIATION
407422	REGULATORY CREDITS - TRANSMISSION DEPRECIATION
407425	REGULATORY CREDITS - DISTRIBUTION DEPRECIATION
407426	REGULATORY CREDITS - GAS DEPRECIATION
407427	REGULATORY CREDITS - COMMON DEPRECIATION
408101	TAX-NON INC-UTIL OPR
408102	REAL AND PERSONAL PROP. TAX
408103	KY PUBLIC SERVICE COMMISSION TAX
408105	FEDERAL UNEMP TAX
408106	FICA TAX
408107	STATE UNEMP TAX
408108	REAL AND PERSONAL PROP TAX - ECR
408195	FEDERAL UNEMP TAX - INDIRECT
408196	FICA TAX - INDIRECT
408197	STATE UNEMP TAX - INDIRECT
408202	TAX-NON INC-OTHER
408203	TC N/A OTHER TAXES
409101	FED INC TAX-UTIL OPR
409102	KY ST INCOME TAXES
409104	FED INC TAXES - EST
409105	ST INC TAXES - EST
409106	FED INC TAX-WKE OPR
409107	KY ST INCOME TAXES-WKE OPR
409201	FED INC TAX-G/L DISP
409203	FED INC TAX-OTHER
409204	ST INC TAX-G/L DISP
409206	ST INC TAX-OTHER
409207	FD IN TX-IMEA/PA FEE
409208	ST IN TX-IMEA/PA FEE
409209	FED IN TAXES-OTH EST
409210	ST INC TAXES-OTH EST
409213	FED CURRENT INC TAX-GAIN ON SALE DISCO
409214	ST CURRENT INC TAX-GAIN ON SALE DISCO
410101	DEF FED INC TAX-OPR
410102	DEF ST INC TAX-OPR
410103	DEF FED INC TAX - OPR EST
410104	DEF ST INC TAX - OPR EST
410106	DEF FED INC TAX-WKE OPR
410107	DEF ST INC TAX-WKE OPR
410108	DEF FED INC TAX-SPEC ITEM
410109	DEF ST INC TAX-SPEC ITEM
410203	DEF FEDERAL INC TX
410204	DEF STATE INC TAX
410211	CLOSED 05/11 - FED INC TAX DEF-GAIN ON SALE DISCO

Account	Account Description
410212	CLOSED 05/11 - STATE INC TAX DEF-GAIN ON SALE DISCO
411101	FED INC TX DEF-CR-OP
411102	ST INC TAX DEF-CR-OP
411106	FED INC TX DEF-CR-WKE OPR
411107	ST INC TAX DEF-CR-WKE OPR
411108	FED INC TX DEF-CR-SPEC ITEM
411109	ST INC TAX DEF-CR-SPEC ITEM
411150	ACCRETION EXPENSE - GENERATION
411151	ACCRETION EXPENSE - TRANSMISSION
411155	ACCRETION EXPENSE - DISTRIBUTION
411156	ACCRETION EXPENSE - GAS
411157	ACCRETION EXPENSE - COMMON
411201	FD INC TX DEF-CR-OTH
411202	ST INC TX DEF-CR-OTH
411211	CLOSED 05/11 - FED INC TAX DEF-GAIN ON SALE DISCO-CREDIT
411212	CLOSED 05/11 - STATE INC TAX DEF-GAIN ON SALE DISCO-CREDIT
411403	ITC DEFERRED
411404	AMORTIZATION OF ITC
411802	GAIN-DISP OF ALLOW
412001	SERVICE COMPANY CONSTRUCTION OR OTHER SERVICES EXP
415001	REVENUE FROM CUSTOMER SERVICE LINES
415004	MERCHANDISE SALES
416001	EXPENSES FROM CUSTOMER SERVICE LINES
416004	MERCHANDISE COST OF SALES
417004	SERVICE CHARGE AND SUPERVISORY FEE - IMEA AND IMPA
417005	IMPA-WORKING CAPITAL
417006	IMEA-WORKING CAPITAL
417010	OTHER MISC REVENUES FROM NON-UTILITY OPERATIONS
417101	CLOSED 05/11 - FUEL - (TC ALLOC ONLY)
417102	STEAM EXPENSES - (TC ALLOC ONLY)
417105	ELECTRIC EXPENSES - (TC ALLOC ONLY)
417106	MISC EXPENSES - (TC ALLOC ONLY)
417107	RENTS
417108	OPERATION SUPERVISION / ENGR - (TC ALLOC ONLY)
417109	EMISSION ALLOWANCES - (TC ALLOC ONLY)
417110	MTCE SUPERVISION/ENG - (TC ALLOC ONLY)
417111	MTCE OF STRUCTURES - (TC ALLOC ONLY)
417112	MTCE OF BOILER PLANT - (TC ALLOC ONLY)
417113	MTCE OF ELEC PLANT - (TC ALLOC ONLY)
417114	MTCE OF MISC PLANT - (TC ALLOC ONLY)
417120	ADMIN AND GEN SAL - (TC ALLOC ONLY)
417121	OFFICE SUPP AND EXP - (TC ALLOC ONLY)
417123	OUSIDE SVCE EMPLOYED - (TC ALLOC ONLY)
417124	PROPERTY INSURANCE - (TC ALLOC ONLY)
417125	INJURIES AND DAMAGES - (TC ALLOC ONLY)
417126	EMPL PENSIONS/BEN - (TC ALLOC ONLY)
417129	DUPLICATE CGS - CR - (TC ALLOC ONLY)
417130	MISC GENERAL EXP - (TC ALLOC ONLY)
417131	ADMIN AND GEN RENTS - (TC ALLOC ONLY)
417135	MTCE OF GEN PLANT - (TC ALLOC ONLY)
418001	NONOPR RENT INCOME
418102	CLOSED 04/11 - DIVIDEND INCOME FROM KU
418105	CLOSED 04/11 - DIVIDEND INCOME FROM LG&E COMPANY
418107	EQUITY IN EARNINGS OF SUBS-EEI
419002	INT INC-US TREAS SEC
419005	INT INC-FED TAX PMT
419006	INT INC-ST TAX PMT
419007	INT INC-NOTES REC
419014	DIVS FROM INVESTMENT
419150	ALLOW FOR FUNDS USED DURING CONSTRUC-EQUITY
419205	INTEREST INCOME FROM FINANCIAL HOLDINGS
419206	INTEREST INCOME FROM OTHER LOANS & RECEIVABLES
419207	INTEREST INCOME FROM SPECIAL FUNDS
419208	INT INC - PPL ENERGY FUNDING
419209	INT INC-ASSOC CO
419211	DIVIDENDS FROM OVEC
420003	AMORTIZATION OF ITC
421001	MISC NONOPR INCOME
421002	FOREIGN EXCHANGE GAINS
421003	CLOSED 02/12 - KM LIFE INS - CASH SURRENDER VALUE
421004	CLOSED 02/12 - MISCELLANEOUS OPERATING INCOME

Account	Account Description
421005	CLOSED 02/12 - MISC NONOPR INCOME-JT USE ASSETS DEPR
421101	GAIN-PROPERTY DISP
421105	GAIN ON ARO SETTLEMENT
421201	LOSS-PROPERTY DISP
421301	PRETAX GAIN/LOSS ON DISPOSAL OF DISC OPERS
421306	PRETAX GAIN/LOSS ON DISPOSAL OF DISC OPERS - CENTURY RECEIVABLE
421550	MTM INCOME - ELECTRIC - NONHEDGING
421552	MTM INCOME - ELECTRIC - NONHEDGING - NETTING
426101	DONATIONS
426191	DONATIONS - INDIRECT
426201	LIFE INSURANCE
426301	PENALTIES
426401	EXP-CIVIC/POL/REL
426491	EXP-CIVIC/POL/REL - INDIRECT
426501	OTHER DEDUCTIONS
426502	SERP
426504	OFFICERS' TIA
426505	OFFICER LONG-TERM INCENT
426508	CLOSED 05/11 - FOREIGN EXCHANGE LOSSES
426509	SERP - NON-MERCER
426511	LOSS ON ASSET IMPAIRMENT
426512	EXPATRIATE BENEFITS
426513	OTHER OFFICER BENEFITS
426515	CLOSED 05/11 - SENIOR MANAGER - LONG TERM INCENTIVE
426517	SERP - INTEREST
426518	GOODWILL IMPAIRMENT
426525	CLOSED 02/12 - UNCOLLECTIBLE NOTES - INDUSTRIAL AUTHORITY
426550	MTM LOSSES - ELECTRIC - NONHEDGING
426556	MTM LOSSES - ELECTRIC - NONHEDGING - NETTING
426557	AMORT OF OCI-PCB JC2003A $128M
426558	AMORT OF REG ASSET - SWAP TERMINATION
426560	ECONOMIC DEVELOPMENT RIDER-CREDITS EARNED
426591	OTHER DEDUCTIONS - INDIRECT
427001	INT-NOTES/DEBENTURES
427007	INT EXP-KU REVOLVING CREDIT $400M 12/14
427009	INT EXP-FMB KU2010 $250M 11/15
427010	INT EXP-FMB KU2010 $500M 11/20
427011	INT EXP-FMB KU2010 $750M 11/40
427014	INT EXP-PCB CC2007A $17.8M 02/26
427015	INT EXP-PCB TC2007A $8.9M 03/37
427016	INT EXP-SR NOTE LKE2010 $400M 11/15
427017	INT EXP-SR NOTE LKE2010 $475M 11/20
427018	INT EXP-SR NOTE LKE2011 $250M 9/21
427019	INT EXP-LGE REVOLVING CREDIT $400M 12/14
427020	INT EXP-FMB LGE2010 $250M 11/15
427021	INT EXP-FMB LGE2010 $285M 11/40
427103	INT EXP-PCB CC2008A $77.9M 02/32
427125	INT EXP-PCB LM/JC2007A $31M 06/33
427126	INT EXP-PCB LM/JC2007B $35.2M 06/33
427127	INT EXP-PCB TC2007A $60M 06/33
427128	INT EXP-PCB JC2000A $25M 05/27
427129	INT EXP-PCB TC2000A $83.3M 08/30
427130	INT EXP-PCB JC2001A $10.1M 09/27
427148	INT EXP-PCB MERC2000A $12.9M 05/23
427161	INT EXP-SWAP-JPM $83.335M 11/20 5.495%
427164	INT EXP-SWAP-MS $32M 10/32 3.657%
427165	INT EXP-SWAP-MS $32M 10/32 3.645%
427166	INT EXP-SWAP-BOA $32M 10/32 3.695%
427168	INT EXP-SWAP-MS $32M 10/32 3.657%
427169	INT EXP-SWAP-MS $32 M 10/32 3.645%
427170	INT EXP-SWAP-BOA $32M 10/32 3.695%
427180	INT EXP-PCB JC2001A $22.5M 9/26
427181	INT EXP-PCB TC2001A $27.5M 9/26
427182	INT EXP-PCB JC2001B $35M 11/27
427183	INT EXP-PCB TC2001B $35M 11/27
427184	INT EXP-PCB CC2002A $20.93M 2/32
427185	INT EXP-PCB CC2002B $2.4M 2/32
427186	INT EXP-PCB MERC2002A $7.4M 2/32
427187	INT EXP-PCB MUHC2002A $2.4M 2/32
427188	INT EXP-PCB CC2002C $96M 10/32
427189	INT EXP-PCB TC2002A $41.665M 10/32

Account	Account Description
427190	INT EXP-PCB JC2003A $128M
427192	INT EXP-PCB CC2004A $50M 10/34
427194	INT EXP-PCB LM/JC2005A $40M 2/35
427199	INT EXP-PCB CC2006B $54M 10/34
427401	HEDGE INEFFECTIVENESS INT RATE SWAP
428007	AM EXP-KU REVOLVING CREDIT $400M 12/14
428009	AM EXP-FMB KU2010 $250M 11/15
428010	AM EXP-FMB KU2010 $500M 11/20
428011	AM EXP-FMB KU2010 $750M 11/40
428013	AM EXP-KU LETTER OF CREDIT FACILITY $198.309M 4/14
428016	AM EXP-SR NOTE LKE2010 $400M 11/15
428017	AM EXP-SR NOTE LKE2010 $475M 11/20
428018	AM EXP-SR NOTE LKE2011 $250M 9/21
428019	AM EXP-LGE REVOLVING CREDIT $400M 12/14
428020	AM EXP-FMB LGE2010 $250M 11/15
428021	AM EXP-FMB LGE2010 $285M 11/40
428031	AM EXP $35.2M 6/33
428035	AM EXP-PCB TC2007A $60M 6/33
428059	AM EXP-PCB JC2001A $10.1M 9/27
428076	AM EXP-PCB TC2000A $83M 8/30
428080	AM EXP-PCB JC2001A $22.5M 9/26
428081	AM EXP-PCB TC2001A $27.5M 9/26
428082	AM EXP-PCB JC2001B $35M 11/27
428083	AM EXP-PCB TC2001B $35M 11/27
428089	AM EXP-PCB TC2002A $41.665M 10/32
428090	OTHER AMORT OR DEBT DISCOUNT AND EXP
428091	AM EXP-PCB LM/JC2003A $128M
428104	AM LOSS-1985J $25M 07/95
428107	AM LOSS-FMB $25M 10/09
428108	AM LOSS-1976B $35.2M 09/06
428109	AM LOSS-1975A $31M 09/00
428110	AM LOSS-1987A $60M 08/97
428124	AM LOSS-PCB JC1990A $25M 06/15
428125	AM LOSS-PCB TC1990A $83.3M 11/20
428126	AM LOSS-PCB LM/JC2007B $35.2M 06/33
428127	AM LOSS-PCB LM/JC2007A $31M 06/33
428128	AM LOSS-PCB JC2000A $25M 05/27
428130	AM LOSS-PCB JC1992A $31M 09/17
428131	AM LOSS-PCB JC1993A $35.2M 08/13
428135	AM LOSS REACQ $60M 6/33
428180	AM LOSS-PCB JC1996A $22.5M 09/26
428181	AM LOSS-PCB TC1996A $27.5M 09/26
428182	AM LOSS-PCB JC1997A $35M 11/27
428183	AM LOSS-PCB TC1997A $35M 11/27
428189	AM LOSS-TC1990B $41.665M 10/20
428190	OTHER AMORT-REACQ DEBT
428191	AM LOSS-JC1993B $26M 11/03
428192	AM LOSS-LM/JC2003A $128M 10/33
428194	AM LOSS-JC1995A $40M 11/05
428196	AM LOSS-PCB LM/JC2005A $40M 02/35
428209	AM DISC-FMB KU2010 $250M 11/15
428210	AM DISC-FMB KU2010 $500M 11/20
428211	AM DISC-FMB KU2010 $750M 11/40
428216	AM DISC-SR NOTE LKE2010 $400M 11/15
428217	AM DISC-SR NOTE LKE2010 $475M 11/20
428218	AM DISC-SR NOTE LKE2011 $250M 9/21
428220	AM DISC-FMB LGE2010 $250M 11/15
428221	AM DISC-FMB LGE2010 $285M 11/40
430002	INT-DEBT TO ASSOC CO
430003	INT EXP ON NOTES TO FIDELIA/PPL (EFF 11/10)
430004	I/C INT EXP - E.ON NORTH AMERICA/PPL (EFF 11/10)
431002	INT-CUST DEPOSITS
431003	INT-FED TAX DEFNCY
431004	INT-OTHER TAX DEFNCY
431008	INT-DSM COST RECOVER
431009	INT-SHORT TERM DEBT-CP
431013	OTHER INT EXP FROM NON-FINANCIAL LIABILITIES
431015	INTEREST ON RATES REFUND-RETAIL
431016	INTEREST ON REFUNDS - MUNICIPALS
431104	INTEREST EXPENSE FROM FINANCIAL LIABILITIES
432001	ALLOW FOR FUNDS USED DURING CONSTRUC-BORROWED

Account	Account Description
433100	REVENUES - DISCONTINUED OPERATIONS
433101	OTHER EXPENSES - DISCONTINUED OPERATIONS
433102	FED CURRENT INCOME TAXES - DISCO OPS
433103	ST CURRENT INCOME TAXES - DISCO OPS
433104	FED DEFERRED INCOME TAXES - DISCO OPS
433105	ST DEFERRED INCOME TAXES - DISCO OPS
438002	CLOSED 06/11 - COMMON STK DIVS DECL - EUSIC
438003	COMMON STK DIVS DECL - LEL
438005	COMMON STK DIVS DECL - PARENT FM KU
438006	COMMON STOCK DIV DECLARED PPL FM LKE
440010	RESID (FUEL) - KWH - (STAT ONLY)
440011	RESID (FUEL) - CUS - (STAT ONLY)
440012	ELECTRIC RESIDENTIAL KW
440101	ELECTRIC RESIDENTIAL DSM
440102	ELECTRIC RESIDENTIAL ENERGY NON-FUEL REV
440103	ELECTRIC RESIDENTIAL ENERGY FUEL REV
440104	ELECTRIC RESIDENTIAL FAC
440111	ELECTRIC RESIDENTIAL ECR
440112	ELECTRIC RESIDENTIAL MSR
440113	ELECTRIC RESIDENTIAL ESM
440114	ELECTRIC RESIDENTIAL VDT
440116	ELECTRIC RESIDENTIAL DEMAND ECR
440117	ELECTRIC RESIDENTIAL ENERGY ECR
440118	ELECTRIC RESIDENTIAL DEMAND CHG REV
440119	ELECTRIC RESIDENTIAL CUST CHG REV
442010	SM COMRC/IND SALE-EL - KWH - (STAT ONLY)
442011	SM COMRC/IND SALE-EL - CUS - (STAT ONLY)
442012	SM COMRC/IND SALE-EL - KW - (STAT ONLY)
442020	LG COMMERC SALES-EL - KWH - (STAT ONLY)
442021	LG COMMERC SALES-EL - CUS - (STAT ONLY)
442022	LG COMMERC SALES-EL - KW - (STAT ONLY)
442025	KU COMMERCIAL SALES - KWH - (STAT ONLY)
442026	KU COMMERCIAL SALES - CUS - (STAT ONLY)
442027	KU COMMERCIAL SALES - KW - (STAT ONLY)
442030	LG INDUSTR SALES-El-OTHER - KWH - (STAT ONLY)
442031	LG INDUSTR SALES-EL-OTHER - CUS - (STAT ONLY)
442034	LG INDUSTR SALES-EL-OTHER - KW - (STAT ONLY)
442035	KU INDUSTRIAL SALES - KWH - (STAT ONLY)
442036	KU INDUSTRIAL SALES - CUS - (STAT ONLY)
442037	KU INDUSTRIAL SALES - KW - (STAT ONLY)
442065	MINE POWER SALES (COAL) - KWH - (STAT ONLY)
442066	MINE POWER SALES (COAL) - CUS - (STAT ONLY)
442067	MINE POWER SALES (COAL) - KW - (STAT ONLY)
442101	ELECTRIC SMALL COMMERCIAL DSM
442102	ELECTRIC SMALL COMMERCIAL ENERGY NON-FUEL REV
442103	ELECTRIC SMALL COMMERCIAL ENERGY FUEL REV
442104	ELECTRIC SMALL COMMERCIAL FAC
442105	ELECTRIC SMALL COMMERCIAL STOD
442111	ELECTRIC SMALL COMMERCIAL ECR
442112	ELECTRIC SMALL COMMERCIAL MSR
442113	ELECTRIC SMALL COMMERCIAL ESM
442114	ELECTRIC SMALL COMMERCIAL VDT
442116	ELECTRIC SMALL COMMERCIAL DEMAND ECR
442117	ELECTRIC SMALL COMMERCIAL ENERGY ECR
442118	ELECTRIC SMALL COMMERCIAL DEMAND CHG REV
442119	ELECTRIC SMALL COMMERCIAL CUST CHG REV
442201	ELECTRIC LARGE COMMERCIAL DSM
442202	ELECTRIC LARGE COMMERCIAL ENERGY NON-FUEL REV
442203	ELECTRIC LARGE COMMERCIAL ENERGY FUEL REV
442204	ELECTRIC LARGE COMMERCIAL FAC
442205	ELECTRIC LARGE COMMERCIAL STOD
442211	ELECTRIC LARGE COMMERCIAL ECR
442212	ELECTRIC LARGE COMMERCIAL MSR
442213	ELECTRIC LARGE COMMERCIAL ESM
442214	ELECTRIC LARGE COMMERCIAL VDT
442216	ELECTRIC LARGE COMMERCIAL DEMAND ECR
442217	ELECTRIC LARGE COMMERCIAL ENERGY ECR
442218	ELECTRIC LARGE COMMERCIAL DEMAND CHG REV
442219	ELECTRIC LARGE COMMERCIAL CUST CHG REV
442301	ELECTRIC INDUSTRIAL DSM
442302	ELECTRIC INDUSTRIAL ENERGY NON-FUEL REV

Account	Account Description
442303	ELECTRIC INDUSTRIAL ENERGY FUEL REV
442304	ELECTRIC INDUSTRIAL FAC
442305	ELECTRIC INDUSTRIAL STOD
442311	ELECTRIC INDUSTRIAL ECR
442312	ELECTRIC INDUSTRIAL MSR
442313	ELECTRIC INDUSTRIAL ESM
442314	ELECTRIC INDUSTRIAL VDT
442316	ELECTRIC INDUSTRIAL DEMAND ECR
442317	ELECTRIC INDUSTRIAL ENERGY ECR
442318	ELECTRIC INDUSTRIAL DEMAND CHG REV
442319	ELECTRIC INDUSTRIAL CUST CHG REV
442601	MINE POWER DSM
442602	MINE POWER ENERGY NON-FUEL REV
442603	MINE POWER ENERGY FUEL REV
442604	MINE POWER FAC
442605	MINE POWER STOD
442611	MINE POWER ECR
442612	MINE POWER MSR
442613	MINE POWER ESM
442614	MINE POWER VDT
442616	MINE POWER DEMAND ECR
442617	MINE POWER ENERGY ECR
442618	MINE POWER DEMAND CHG REV
442619	MINE POWER CUST CHG REV
444010	PUBLIC ST/HWY LIGHTS - KWH - (STAT ONLY)
444011	PUBLIC ST/HWY LIGHTS - CUS - (STAT ONLY)
444012	PUBLIC ST/HWY LIGHTS - KW - (STAT ONLY)
444101	ELECTRIC STREET LIGHTING DSM
444102	ELECTRIC STREET LIGHTING ENERGY NON-FUEL REV
444103	ELECTRIC STREET LIGHTING ENERGY FUEL REV
444104	ELECTRIC STREET LIGHTING FAC
444105	ELECTRIC STREET LIGHTING STOD
444111	ELECTRIC STREET LIGHTING ECR
444112	ELECTRIC STREET LIGHTING MSR
444113	ELECTRIC STREET LIGHTING ESM
444114	ELECTRIC STREET LIGHTING VDT
444117	ELECTRIC STREET LIGHTING ENERGY ECR
444118	ELECTRIC STREET LIGHTING DEMAND CHG REV
444119	ELECTRIC STREET LIGHTING CUST CHG REV
445010	SALES-PUB AUTH-ELEC - KWH - (STAT ONLY)
445011	SALES-PUB AUTH-ELEC - CUS - (STAT ONLY)
445012	SALES-PUB AUTH-ELEC - KW - (STAT ONLY)
445030	MUNICIPAL PUMPING - KWH - (STAT ONLY)
445031	MUNICIPAL PUMPING - CUS - (STAT ONLY)
445032	MUNICIPAL PUMPING - KW - (STAT ONLY)
445101	ELECTRIC PUBLIC AUTH DSM
445102	ELECTRIC PUBLIC AUTH ENERGY NON-FUEL REV
445103	ELECTRIC PUBLIC AUTH ENERGY FUEL REV
445104	ELECTRIC PUBLIC AUTH FAC
445105	ELECTRIC PUBLIC AUTH STOD PCR
445111	ELECTRIC PUBLIC AUTH ECR
445112	ELECTRIC PUBLIC AUTH MSR
445113	ELECTRIC PUBLIC AUTH ESM
445114	ELECTRIC PUBLIC AUTH VDT
445116	ELECTRIC PUBLIC AUTH DEMAND ECR
445117	ELECTRIC PUBLIC AUTH ENERGY ECR
445118	ELECTRIC PUBLIC AUTH DEMAND CHG REV
445119	ELECTRIC PUBLIC AUTH CUST CHG REV
445301	MUNI PUMPING DSM
445302	MUNI PUMPING ENERGY NON-FUEL REV
445303	MUNI PUMPING ENERGY FUEL REV
445304	MUNI PUMPING FAC
445305	MUNICIPAL PUMPING STOD
445311	MUNI PUMPING ECR
445312	MUNI PUMPING MSR
445313	MUNI PUMPING ESM
445314	MUNI PUMPING VDT
445316	MUNI PUMPING DEMAND ECR
445317	MUNI PUMPING ENERGY ECR
445318	MUNI PUMPING DEMAND CHG REV
445319	MUNI PUMPING CUST CHG REV

Account	Account Description
447005	I/C SALES - OSS
447006	I/C SALES NL
447010	FIRM SALES - ENERGY-OTHER - KWH - (STAT ONLY)
447011	FIRM SALES - ENERGY-OTHER - CUS - (STAT ONLY)
447016	CLOSED 04/11 - SALES - MISO DAY 2 - OSS
447017	FIRM SALES - ENERGY-OTHER - KW - (STAT ONLY)
447021	FIRM SALES - MUNI/BEREA - KWH - (STAT ONLY)
447022	FIRM SALES - MUNI/BEREA - CUS
447023	FIRM SALES - MUNICIPALS - KW - (STAT ONLY)
447049	SPOT SALES - ENERGY
447050	SPOT SALES - ENERGY - KWH
447051	SPOT SALES - ENERGY - KW - (STAT ONLY)
447100	BROKERED SALES
447110	SETTLED SWAP REVENUE
447200	BROKERED PURCHASES
447210	SETTLED SWAP EXPENSE
447302	RESALE MUNICIPALS BASE REV
447303	RESALE MUNICIPALS BASE REV FUEL
447304	RESALE MUNICIPALS FAC
447318	RESALE MUNICIPALS DEMAND CHG REV
447319	RESALE MUNICIPALS CUST CHG REV
449102	PROVISION FOR RATE REFUND/COLLECTION
449105	RATE REFUNDS-RETAIL
450001	FORFEITED DISC/LATE PAYMENT CHARGE-ELEC
450002	FORFEITED DISC/LATE PAYMENT CHARGE - MUNI INTEREST
451001	RECONNECT CHRG-ELEC
451002	TEMPORARY SERV-ELEC
451004	OTH SERVICE REV-ELEC
454001	CATV ATTACH RENT
454002	OTH RENT-ELEC PROP
454003	RENT FRM FIBER OPTIC
454006	FACILITY CHARGES
454900	I/C JOINT USE RENT REVENUE-ELEC-INDIRECT
456003	COMP-TAX REMIT-ELEC
456004	COMP-STBY PWR-H2O CO
456007	RET CHECK CHRG-ELEC
456008	OTHER MISC ELEC REVS
456022	COAL RESALE REVENUES
456028	EXCESS FACILITIES CHARGES/NRB ELECTRIC REV (ENDED 04/09)
456029	GYPSUM REVENUES
456030	FORFEITED REFUNDABLE ADVANCES
456099	PWR DEL TO GOVT - (STAT ONLY)
456101	BASE OTHER ELECTRIC REVENUES-WHEELING-MISO - (STAT ONLY)
456102	ANCILLARY SERVICE SCHEDULE 1-MISO
456103	ANCILLARY SERVICE SCHEDULE 2-MISO
456105	ANCILLARY SERVICE SCHEDULE 1-OSS-MISO
456106	ANCILLARY SERVICE SCHEDULE 2-OSS-MISO
456109	NL TRANSMISSION OF ELECTRIC ENERGY-3RD PARTY
456114	INTERCOMPANY TRANSMISSION REVENUE - RETAIL SOURCING OSS
456116	INTERCOMPANY TRANSMISSION REVENUE - MUNICIPALS
456118	INTRACOMPANY TRANSMISSION REVENUE - NATIVE LOAD
456119	INTRACOMPANY TRANSMISSION REVENUE - RETAIL SOURCING OSS
456124	I/C TRANSMISSION RETAIL REVENUE - NATIVE LOAD
456127	TRANSMISSION SERVICE REVENUE - CC (OSS-STAT ONLY)
456198	INTRACOMPANY TRANSMISSION REVENUE ELIMINATION - NL
456199	INTRACOMPANY TRANSMISSION REVENUE ELIMINATION - RETAIL SOURCING OSS
457101	DIRECT COSTS CHARGED
457201	INDIRECT COSTS CHARGED
480010	RESID VARIABLE(FUEL) - MCF - (STAT ONLY)
480011	RESID VARIABLE(FUEL) - CUS - (STAT ONLY)
480101	GAS RESIDENTIAL DSM
480102	GAS RESIDENTIAL ENERGY REV
480104	GAS RESIDENTIAL GSC
480107	GAS RESIDENTIAL WNA
480114	GAS RESIDENTIAL VDT
480119	GAS RESIDENTIAL CUST CHG REV
481010	COMMERCIAL SALES-GAS - CU - (STAT ONLY)
481011	COMMERCIAL SALES-GAS - MCF - (STAT ONLY)
481020	INDUSTRIAL SALES-GAS - CU - (STAT ONLY)
481021	INDUSTRIAL SALES-GAS - MCF - (STAT ONLY)
481101	GAS COMMERCIAL DSM

Account	Account Description
481102	GAS COMMERCIAL ENERGY REV
481104	GAS COMMERCIAL GSC
481105	GAS COMMERCIAL CASHOUT
481107	GAS COMMERCIAL WNA
481114	GAS COMMERCIAL VDT
481119	GAS COMMERCIAL CUST CHG REV
481202	GAS INDUSTRIAL ENERGY REV
481204	GAS INDUSTRIAL GSC
481205	GAS INDUSTRIAL CASHOUT
481214	GAS INDUSTRIAL VDT
481219	GAS INDUSTRIAL CUST CHG REV
482010	SALES-PUB AUTH-GAS - CUS - (STAT ONLY)
482011	SALES-PUB AUTH-GAS - MCF - (STAT ONLY)
482101	GAS PUBLIC AUTH DSM
482102	GAS PUBLIC AUTH ENERGY REV
482104	GAS PUBLIC AUTH GSC
482105	GAS PUBLIC AUTH CASHOUT
482107	GAS PUBLIC AUTH WNA
482114	GAS PUBLIC AUTH VDT
482119	GAS PUBLIC AUTH CUST CHG REV
483001	OFF SYSTEM SALES FOR RESALE (MCF) - (STAT ONLY)
484001	GAS INTERDEPARTMENTAL SALES
484102	GAS INTERDEPARTMENTAL BASE REVENUES
484104	GAS INTERDEPARTMENTAL GSC
484114	CLOSED 05/11 - GAS INTERDEPARTMENTAL VDT
484119	GAS INTERDEPARTMENTAL CUSTOMER CHARGE
487001	FORFEITED DISC/LATE PAYMENT CHARGE-GAS
488001	RECONNECT CHRG-GAS
488003	INSPECTION CHARGE-GAS
488004	METER TESTS-GAS
488005	GAS METER PULSE SERVICE
489201	GAS TRANSPORT INTERDEPARTMENTAL - BASE
489204	GAS TRANSPORT INTERDEP - CASHOUT OFO/UCDI
489214	CLOSED 05/11 - GAS TRANSPORT INTERDEPARTMENTAL - VDT
489215	GAS TRANSPORT - INTERDEPARTMENTAL
489219	CLOSED 05/11 - GAS TRANSPORT INTERDEPARTMENTAL - CUSTOMER CHARGE
489301	GAS TRANSPORT - DSM
489302	GAS TRANSPORT - INDUSTRIAL
489304	GAS TRANSPORT - CASHOUT OFO/UCDI
489310	GAS TRANSPORT - CUSTOMERS (STAT ONLY)
489312	GAS TRANSPORT - DIRECT PAY - STATS ONLY
489314	GAS TRANSPORT - VDT
489319	TRANSPORT GAS - CUSTOMER CHARGE
489322	GAS TRANSPORT - COMMERCIAL
489332	GAS TRANSPORT - PUBLIC AUTHORITY
493001	RENT-GAS PROPERTY
493900	I/C JOINT USE RENT REVENUE-GAS-INDIRECT
495002	COMP-TAX REMIT-GAS
495005	RET CHECK CHRG-GAS
495006	OTHER GAS REVENUES
495102	PURCHASED GAS REFUND
495103	OVER/UNDER GAS SUPPLY COST ACTUAL ADJ
495104	OVER/UNDER GAS SUPPLY COST BALANCE ADJ
495107	WHOLESALE SALES MARGIN
495108	ACQ AND TRANS INCENTIVE
495109	PRB RECOVERY
500100	OPER SUPER/ENG
500900	OPER SUPER/ENG - INDIRECT
501001	FUEL-COAL - TON
501002	FUEL-COAL - BTU - (STAT ONLY)
501003	COAL ADDITIVES
501004	FUEL COAL - TO SOURCE UTILITY OSS
501005	FUEL COAL - OSS
501006	FUEL COAL - OFFSET
501007	FUEL COAL - TO SOURCE UTILITY RETAIL
501020	START-UP OIL -GAL
501021	START-UP OIL - BTU - (STAT ONLY)
501022	STABILIZATION OIL - GAL
501023	STABILIZATION OIL - BTU - (STAT ONLY)
501024	GENERATION OIL - GAL - (STAT ONLY)
501025	GENERATION OIL - BTU - (STAT ONLY)

Account	Account Description
501026	COAL RESALE EXPENSES
501030	PETROLEUM COKE - TON - (STAT ONLY)
501090	FUEL HANDLING
501091	FUEL SAMPLING AND TESTING
501092	FUEL HANDLING-GALS - (STAT ONLY)
501099	KWH GENERATED-COAL - (STAT ONLY)
501100	START-UP GAS - MCF
501101	START-UP GAS - BTU - (STAT ONLY)
501102	STABILIZATION GAS - MCF
501103	STABILIZATION GAS - BTU - (STAT ONLY)
501110	GENERATION GAS - MAIN BOILER -MCF - (STAT ONLY)
501200	BOTTOM ASH DISPOSAL
501201	PLANT-ECR BOTTOM ASH DISPOSAL
501202	BOTTOM ASH PROCEEDS
501203	ECR BOTTOM ASH DISPOSAL
501250	FLY ASH PROCEEDS
501251	FLY ASH DISPOSAL
501252	PLANT-ECR FLY ASH DISPOSAL
501253	ECR FLY ASH DISPOSAL
501299	KWH GENERATED-OIL - (STAT ONLY)
501990	FUEL HANDLING - INDIRECT
501993	FUELS PROCUREMENT - INDIRECT
502001	OTHER WASTE DISPOSAL
502002	BOILER SYSTEMS OPR
502003	SDRS OPERATION
502004	SDRS-H2O SYS OPR
502005	SLUDGE STAB SYS OPR
502006	SCRUBBER REACTANT EX
502011	ECR OTHER WASTE DISPOSAL
502012	PLANT-ECR LANDFILL OPERATION
502013	ECR LANDFILL OPERATIONS
502021	OTHER WASTE DISPOSAL - RETAIL
502022	OTHER WASTE DISPOSAL - OSS
502023	OTHER WASTE DISPOSAL - OFFSET
502024	SCRUBBER REACTANT - RETAIL
502025	SCRUBBER REACTANT - OSS
502026	SCRUBBER REACTANT - OFFSET
502056	ECR SCRUBBER REACTANT EX
502100	STM EXP(EX SDRS.SPP)
502900	STM EXP(EX SDRS.SPP) - INDIRECT
504001	STEAM XFERRED - CR - PROJECT USE
505100	ELECTRIC SYS OPR
506001	STEAM OPERATION-AIR QUALITY MONITORING AND CONTROL EQUIPMENT
506051	ECR STEAM OPERATION-AIR QUALITY MONITORING AND CONTROL EQUIPMENT
506100	MISC STM PWR EXP
506102	MISC STM PWR EXP-GALS - (STAT ONLY)
506103	MISC STM PWR EXP-BTU - (STAT ONLY)
506104	NOX REDUCTION REAGENT
506105	OPERATION OF SCR/NOX REDUCTION EQUIP
506106	SCR/NOX - RETAIL
506107	SCR/NOX - OSS
506108	SCR/NOX - OFFSET
506109	SORBENT INJECTION OPERATION
506110	MERCURY MONITORS OPERATIONS
506111	ACTIVATED CARBON
506112	SORBENT REACTANT - REAGENT ONLY
506150	ECR MERCURY MONITORS OPERATIONS
506151	ECR ACTIVATED CARBON
506152	ECR SORBENT REACTANT - REAGENT ONLY
506154	ECR NOX REDUCTION REAGENT
506155	ECR OPERATION OF SCR/NOX REDUCTION EQUIP
506156	ECR BAGHOUSE OPERATIONS
506159	ECR SORBENT INJECTION OPERATION
506900	MISC STM PWR EXP - INDIRECT
507100	RENTS-STEAM
509002	SO2 EMISSION ALLOWANCES
509003	NOX EMISSION ALLOWANCES
509004	EMISSION ALLOWANCES - RETAIL
509007	EMISSION ALLOWANCES - OSS
509008	EMISSION ALLOWANCES - OFFSET
509052	ECR SO2 EMISSION ALLOWANCES

Account	Account Description
509053	ECR NOX EMISSION ALLOWANCES
510100	MTCE SUPER/ENG - STEAM
511100	MTCE-STRUCTURES
512005	MAINTENANCE-SDRS
512011	INSTR/CNTRL-ENVRNL
512015	SDRS-COMMON H2O SYS
512017	MTCE-SLUDGE STAB SYS
512051	ECR INSTR/CNTRL-ENVRNL
512055	ECR MAINTENANCE-SDRS
512100	MTCE-BOILER PLANT
512101	MAINTENANCE OF SCR/NOX REDUCTION EQUIP
512102	SORBENT INJECTION MAINTENANCE
512103	MERCURY MONITORS MAINTENANCE
512105	PLANT-ECR LANDFILL MAINTENANCE
512106	PLANT-ECR CCP SYSTEM MAINTENANCE
512107	ECR LANDFILL MAINTENANCE
512108	ECR CCP SYSTEM MAINTENANCE
512151	ECR MAINTENANCE OF SCR/NOX REDUCTION EQUIP
512152	ECR SORBENT INJECTION MAINTENANCE
512153	ECR MERCURY MONITORS MAINTENANCE
512156	ECR BAGHOUSE MAINTENANCE
513100	MTCE-ELECTRIC PLANT
513900	MTCE-ELECTRIC PLANT - BOILER
514100	MTCE-MISC/STM PLANT
535100	OPER SUPER/ENG-HYDRO
536100	WATER FOR POWER
536101	KWH GENERATED-HYDRO - (STAT ONLY)
538100	ELECTRIC EXPENSES - HYDRO
539100	MISC HYD PWR GEN EXP
540100	RENTS-HYDRO
541100	MTCE-SUPER/ENG - HYDRO
542100	MAINT OF STRUCTURES - HYDRO
543100	MTCE-RES/DAMS/WATERW
544100	MTCE-ELECTRIC PLANT
545100	MTCE-MISC HYDAULIC PLANT
546100	OPER SUPER/ENG - TURBINES
547010	KWH GEN-OTH PWR-OIL - (STAT ONLY)
547020	KWH GEN-OTH PWR-GAS - (STAT ONLY)
547030	FUEL-GAS - MCF
547031	FUEL-GAS - BTU - (STAT ONLY)
547040	FUEL-OIL - GAL
547041	FUEL-OIL - BTU - (STAT ONLY)
547051	FUEL - TO SOURCE UTILITY OSS
547052	FUEL - OSS
547053	FUEL - OFFSET
547054	FUEL - TO SOURCE UTILITY RETAIL
547056	FUEL - GAS - INTRACOMPANY
547057	FUEL - GAS - INTRACOMPANY - BTU - (STAT ONLY)
548100	GENERATION EXP
549001	CLOSED 05/11 - SO2 EMISSION ALLOWANCES-CT'S
549002	AIR QUALITY EXPENSES
549003	NOX EMISSION ALLOWANCES
549051	CLOSED 05/11 - ECR SO2 EMISSON ALLOWANCES-CTS
549053	CLOSED 05/11 - ECR NOX EMISSION ALLOWANCES
549100	MISC OTH PWR GEN EXP
550100	RENTS-OTH PWR
551100	MTCE-SUPER/ENG - TURBINES
552100	MTCE-STRUCTURES - OTH PWR
553100	MTCE-GEN/ELECT EQ
554100	MTCE-MISC OTH PWR GEN
555006	CLOSED 04/11 - MISO DAY 2 PURCHASED POWER - OSS
555007	CLOSED 04/11 - MISO DAY 2 PURCHASED POWER - NL
555010	OSS POWER PURCHASES
555015	NL POWER PURCHASES - ENERGY
555016	NL POWER PURCHASES - DEMAND
555020	OSS I/C POWER PURCHASES
555025	NL I/C POWER PURCHASES
555080	PURCHASE POWER NATIVE LOAD - SQF AND LQF TARIFF
555085	PURCHASE POWER NATIVE LOAD DEMAND - LQF TARIFF
555101	INAD INTER REC-KWH - (STAT ONLY)
555110	INAD INTER DEL-KWH - (STAT ONLY)

Account	Account Description
556100	SYS CTRL / DISPATCHING
556900	SYS CTRL / DISPATCHING - INDIRECT
557100	OTH POWER SUPPLY EXP
557110	MARKET FEES - NATIVE LOAD
557111	MARKET FEES - OFF SYSTEM SALES
557206	MISO DAY 2 OTHER - NATIVE LOAD
557207	MISO DAY 2 OTHER - OFF SYSTEM SALES
557208	RTO OTHER (NON-MISO) - NL
557209	RTO OTHER (NON-MISO) - OSS
557211	RTO OPERATING RESRV (NON-MISO) - NL
557212	RTO OPERATING RESRV (NON-MISO) - OSS
557999	KU PLANT ALLOCATION CLEARING ACCOUNT
560100	OP SUPER/ENG-SSTOPER
560900	OP SUPER/ENG-SSTOPER - INDIRECT
561100	LOAD DISPATCH-WELOB
561190	LOAD DISPATCH - INDIRECT
561402	MISO DAY 1 SCH 10 - RESERVE
561403	NL MISO D1 SCHEDULE 10 - SCHEDULING, SYSTEM CONTROLS
561501	RELIABILITY, PLANNING AND STANDARDS DEVELOPMENT
561590	RELIABILITY, PLANNING AND STANDARDS DEVELOPMENT - INDIRECT
561601	TRANSMISSION SERVICE STUDIES
561801	MISO DAY 1 SCH 10 - LOAD
561802	MISO DAY 1 SCH 10 - RESERVE
561803	NL MISO D1 SCHEDULE 10 - RELIABILITY PLANNING
561900	LOAD DISPATCH-WELOB - INDIRECT
561901	BALANCING AUTHORITY EXPENSE (LABOR ONLY)
562100	STA EXP-SUBST OPER
563100	OTHER INSP-ELEC TRAN
563900	OTHER INSP-ELEC TRAN - INDIRECT
565002	TRANSMISSION ELECTRIC OSS
565005	TRANSMISSION ELECTRIC NATIVE LOAD
565006	TRANSMISSION ELECTRIC OSS - MISO
565007	TRANSMISSION ELECTRIC OSS - 3RD PARTY
565014	INTERCOMPANY TRANSMISSION EXPENSE
565016	INTERCOMPANY TRANSMISSION EXPENSE - MUNICIPALS
565018	INTRACOMPANY TRANSMISSION EXPENSE - NATIVE LOAD
565019	INTRACOMPANY TRANSMISSION EXPENSE - OSS
565024	I/C TRANSMISSION RETAIL EXPENSE - NATIVE LOAD
565198	INTRACOMPANY TRANSMISSION EXPENSE OFFSET - NATIVE LOAD
565199	INTRACOMPANY TRANSMISSION EXPENSE ELIMINATION - RETAIL SOURCING OSS
566100	MISC TRANS EXP-SSTMT
566122	REACTIVE SUPPLY & VOLTAGE CONTROL - NL
566140	INDEPENDENT OPERATOR
566150	EKPC DEPANCAKING SETTLEMENT
566151	KMPA MISO CHARGES
566900	MISC TRANS EXP-SSTMT - INDIRECT
567100	RENTS-ELEC/SUBSTATION OPERATIONS
567900	I/C JOINT USE RENT EXPENSE-TRANS-INDIRECT
569100	MTCE-STRUCT-SSTMTCE
569101	MAINTENANCE OF COMPUTER HARDWARE
570100	MTCE-ST EQ-SSTMTCE
571100	MTCE OF OVERHEAD LINES
573100	MTCE-MISC TR PLT-SSTMT
575701	MISO DAY 2 SCH 17-MARKET ADMIN FEE-OSS
575702	MISO DAY 2 SCH 16-FTR ADMIN FEE-NL
575703	MISO DAY 2 SCH 17-MARKET ADMIN FEE-NL
575704	MISO DAY 1 SCH 10 - RESERVE
575708	NL MISO D1 SCHEDULE 10 - MKT ADMIN
580100	OP SUPER/ENG-SSTOPER
580900	OP SUPER/ENG-SSTOPER - INDIRECT
581900	SYS CTRL/SWITCH-DIST - INDIRECT
582100	STATION EXP-SSTOPER
583001	OPR-O/H LINES
583003	O/H LOAD/VOLT TEST
583004	INST/REMV TEMP SERV
583005	CUST COMPL RESP-O/H
583008	INST/REMV TRANSF/REG
583009	INSPC O/H LINE FACIL
583010	LOC O/H ELEC FAC-BUD
583100	O/H LINE EXP-SSTOPER
584001	OPR-UNDERGRND LINES

Account	Account Description
584002	INSPC U/G LINE FACIL
584003	LOAD/VOLT TEST-U/G
584005	RESP-U/G CUST COMPL
584008	INST/RMV/REPL TRANSF
585100	STREET LIGHTING AND SIGNAL SYST EXP
586100	METER EXP
586101	INPECT/TEST METERS
586900	METER EXP - INDIRECT
587100	CUST INSTALLATION EXP
588100	MISC DIST EXP-SUBSTATION OPERATIONS
588900	MISC DIST EXP-SUBSTATION OPERATIONS - INDIRECT
589100	RENTS-DISTR / SUBSTAT OPER
590100	MTCE/SUPER/ENG-SSTMT
590900	MTCE/SUPER/ENG-SSTMT - INDIRECT
591003	MTCE-MISC STRUCT-DIS
592100	MTCE-ST EQ-SSTMTCE
593001	MTCE-POLE/FIXT-DISTR
593002	MTCE-COND/DEVICE-DIS
593003	MTCE-SERVICES
593004	TREE TRIMMING
593005	MINOR EXEMPT EXPENSE
594001	MTCE-ELEC MANHOL ETC
594002	MTCE-U/G COND ETC
595100	MTCE-TRANSF/REG
596100	MTCE OF STREET LIGHTING AND SIGNALS
598100	MTCE OF MISC DISTRIBUTION PLANT
803001	GAS TRANS LINE PURCH
803002	PURCHASED GAS REFUND
803003	GAS COST ACTUAL ADJ
803004	GAS COST BALANCE ADJ
803006	PURCHASED GAS - WHOLESALE SALES
803007	WHOLESALE SALES MARGIN
803008	ACQ AND TRANS INCENTIVE
803009	PBR RECOVERY
803010	END USERS GAS PURCHASE (MCF ONLY) - (STAT ONLY)
806001	EXCHANGE GAS
807001	PURCH GAS CALC EXP
807002	OTHER PURCH GAS EXP
807003	GAS PROCUREMENT EXP
807401	PURCH GAS CALC EXP
807501	OTHER PURCH GAS EXP
807502	GAS PROCUREMENT EXP
808101	GAS W/D FROM STOR-DR
808201	GAS DEL'D TO STOR-CR
810001	GAS-COMP STA FUEL-CR
812010	GAS-FUEL-ELEC GEN-CR - MCF - (STAT ONLY)
812011	GAS-FUEL-ELEC GEN-CR - BTU - (STAT ONLY)
812020	GAS-CITY GATE-CR
812030	GAS-OTH DEPT-CR
812040	GAS-START/STABIL-CR - MCF - (STAT ONLY)
812041	GAS-START/STABIL-CR - BTU - (STAT ONLY)
813001	OTH GAS SUPPLY EXP
813002	CLOSED 08/11 - GAS PURIFICATION EXPENSE
814003	SUPV-STOR/COMPR STA
816100	WELLS EXPENSE
817100	LINES EXPENSE
818100	COMPR STATION EXP
819100	COMPR STA FUEL-U/G
821100	PURIFICATION EXP
823100	GAS LOSSES
824100	OPR-U/G STO/COMPR
825100	ROYALTIES
826100	RENTS-STORAGE FIELDS
830100	MTCE SUPRV AND ENGR - STOR COMPR
832100	MTC-RESERVOIRS/WELLS
833100	MTCE-LINES
834100	MTCE-COMP STA EQUIP
835100	MTCE-M/R EQ-COMPR
836100	MTCE-PURIFICATION EQUP
837100	MTCE-OTHER EQUIP
850100	OPR SUPV AND ENGR

Account	Account Description
851100	SYS CTRL/DSPTCH-GAS
852100	OPR-COM EQ-GAS TRANS
856100	MAINS EXPENSES
860100	RENTS-GAS TRANS
863100	MTCE-GAS MAINS-TRANS
871100	DISTR LOAD DISPATCH
874001	OTHER MAINS/SERV EXP
874002	LEAK SUR-DIST MN/SVC
874005	CHEK STOP BOX ACCESS
874006	PATROLLING MAINS
874007	CHEK/GREASE VALVES
874008	OPR-ODOR EQ
875100	MEAS/REG STA-GENERAL
876100	MEAS/REG STA-INDUSTRIAL
877100	MEAS/REG STA-CITY GATE
878100	METER/REG EXPENSE
879100	CUST INSTALL EXPENSE
880016	GAS LOST / UNACCT FOR (MCF) - (STAT ONLY)
880100	OTH GAS DISTR EXPENSE
880900	OTH GAS DISTR EXPENSE - INDIRECT
881100	RENTS-GAS DISTR
886100	MTCE-GAS DIST STRUCT
887100	MTCE-GAS MAINS-DISTR
889100	MTCE-M/R STA EQ-GENL
890100	MTCE-M/R STA EQ-INDL
891100	MTCE-M/R ST EQ-CITY GATE
892100	MTCE-OTH SERVICES
894100	MTCE-OTHER EQUIP
901001	SUPV-CUST ACCTS
901900	SUPV-CUST ACCTS - INDIRECT
902001	METER READ-SERV AREA
902002	METER READ-CLER/OTH
902900	METER READ-SERV AREA - INDIRECT
903001	AUDIT CUST ACCTS
903002	BILL SPECIAL ACCTS
903003	PROCESS METER ORDERS
903006	CUST BILL/ACCTG
903007	PROCESS PAYMENTS
903008	INVEST THEFT OF SVC
903011	MAINTENANCE-CIS
903012	PROC CUST CNTRT/ORDR
903013	HANDLE CREDIT PROBS
903022	COLL OFF-LINE BILLS
903023	PROC BANKRUPT CLAIMS
903025	MTCE-ASST PROGRAMS
903030	PROC CUST REQUESTS
903031	PROC CUST PAYMENTS
903032	DELIVER BILLS-REG
903035	COLLECTING-OTHER
903036	CUSTOMER COMPLAINTS
903038	MISC CASH OVERAGE/SHORTAGE
903902	BILL SPECIAL ACCTS - INDIRECT
903903	PROCESS METER ORDERS - INDIRECT
903906	CUST BILL/ACCTG - INDIRECT
903907	PROCESS PAYMENTS - INDIRECT
903909	PROC EXCEPTION PMTS - INDIRECT
903912	PROC CUST CNTRT/ORDR - INDIRECT
903930	PROC CUST REQUESTS - INDIRECT
903931	PROC CUST PAYMENTS - INDIRECT
903936	CUSTOMER COMPLAINTS - INDIRECT
904001	UNCOLLECTIBLE ACCTS
904002	UNCOLLECTABLE ACCTS - WHOLESALE
904003	UNCOLL ACCTS - A/R MISC
904004	UNCOLL ACCTS - A/R MISC - SPEC ITEM
905001	MISC CUST SERV EXP
905002	MISC CUST BILL/ACCTG
905003	MISC COLLECTING EXP
907001	SUPV-CUST SER/INFO
907900	SUPV-CUST SER/INFO - INDIRECT
908001	CUST MKTG/ASSIST
908004	DSM - ENERGY AUDIT

Account	Account Description
908005	DSM CONSERVATION PROG
908006	DSM - HVAC
908007	DSM - CONSERVATION
908009	MISC MARKETING EXP
908010	CLOSED 04/11 - DSM CONSERVATION PROG - OFFSET
908901	CUST MKTG/ASSIST - INDIRECT
908902	RES CONS/ENG ED PROG - INDIRECT
908909	MISC MARKETING EXP - INDIRECT
909004	MISC CUST COM-SER/IN
909005	MEDIA RELATIONS
909010	PRINT ADVER-SER/INFO
909011	OTH ADVER-SER/INFO
909013	SAFETY PROGRAMS
910001	MISC CUST SER/INFO
910900	MISC CUST SER/INFO - INDIRECT
912003	GEN MKTG AND MKTG PGMS
913012	OTH ADVER-SALES
920100	OTHER GENERAL AND ADMIN SALARIES
920900	OTHER GENERAL AND ADMIN SALARIES - INDIRECT
921002	EXP-GEN OFFICE EMPL
921003	GEN OFFICE SUPPL/EXP
921004	OPR-GEN OFFICE BLDG
921902	INDIRECT EMPLOYEE OFFICE EXPENSE ALLOCATION
921903	GEN OFFICE SUPPL/EXP - INDIRECT
921904	OPR-GEN OFFICE BLDG - INDIRECT
922001	A/G SAL TRANSFER-CR
922002	OFF SUPP/EXP TRAN-CR
922003	TRIMBLE CTY TRAN-CR
923100	OUTSIDE SERVICES
923101	OUTSIDE SERVICES - AUDIT FEES - PWC
923102	OUTSIDE SERVICES - TAX SERVICES - PWC
923103	OUTSIDE SERVICES - NON-AUDIT SERVICES - PWC
923301	OUTSIDE SERVICES - AUDIT FEES - OTHER
923302	OUTSIDE SERVICES - TAX SERVICES - OTHER
923303	OUTSIDE SERVICES - NON-AUDIT SERVICES - OTHER
923900	OUTSIDE SERVICES - INDIRECT
924100	PROPERTY INSURANCE
925001	PUBLIC LIABILITY
925002	WORKERS COMP EXPENSE - BURDENS
925003	AUTO LIABILITY
925004	SAFETY AND INDUSTRIAL HEALTH
925100	OTHER INJURIES AND DAMAGES
925902	WORKERS COMP EXPENSE - BURDENS INDIRECT
925904	SAFETY & INDUSTRIAL HEALTH - INDIRECT
926001	TUITION REFUND PLAN
926002	GROUP LIFE INSURANCE EXPENSE - BURDENS
926003	MEDICAL INSURANCE EXPENSE - BURDENS
926004	DENTAL INSURANCE EXPENSE - BURDENS
926005	LONG TERM DISABILITY EXPENSE - BURDENS
926019	OTHER BENEFITS EXPENSE - BURDENS
926100	EMPLOYEE BENEFITS - NON-BURDEN
926101	PENSIONS EXPENSE - BURDENS
926102	401K EXPENSE - BURDENS
926105	FASB 112 (OPEB) POST EMPLOYMENT EXPENSE - BURDENS
926106	FASB 106 (OPEB) POST RETIREMENT EXPENSE - BURDENS
926110	EMPLOYEE WELFARE
926112	PENSION EXP- VA
926113	PENSION EXP- FERC
926115	ADOPTION ASSISTANCE PROGRAM
926116	RETIREMENT INCOME EXPENSE - BURDENS
926117	CLOSED 04/11 - PENSION INTEREST EXPENSE - BURDENS
926118	CLOSED 04/11 - FASB 106 INTEREST (OPEB) POST RETIREMENT EXPENSE - BURDENS
926901	TUITION REFUND PLAN - INDIRECT
926902	GROUP LIFE INSURANCE EXPENSE - BURDENS INDIRECT
926903	MEDICAL INSURANCE EXPENSE - BURDENS INDIRECT
926904	DENTAL INSURANCE EXPENSE - BURDENS INDIRECT
926905	LONG TERM DISABILITY EXPENSE - BURDENS INDIRECT
926911	PENSIONS EXPENSE - BURDENS INDIRECT
926912	401K EXPENSE - BURDENS INDIRECT
926915	FASB 112 (OPEB) POST EMPLOYMENT EXPENSE - BURDENS INDIRECT
926916	FASB 106 (OPEB) POST RETIREMENT EXPENSE - BURDENS INDIRECT

Account	Account Description
926917	PENSION INTEREST EXPENSE - BURDENS INDIRECT
926918	FASB 106 INTEREST (OPEB) POST RETIREMENT EXPENSE - BURDENS INDIRECT
926919	OTHER BENEFITS EXPENSE - BURDENS INDIRECT
926990	RETIREMENT INCOME EXPENSE - BURDENS INDIRECT
927001	ELEC SUPPL W/O CH-DR
927002	OTH ITEMS W/O CH-DR
927003	CITY OF LOU GAS FRAN
928001	FORMAL CASES-REG COM
928002	REG UPKEEP ASSESSMTS
928003	AMORTIZATION OF RATE CASE EXPENSES
928006	FORMAL CASES - TENNESSEE
928007	FORMAL CASES - VIRGINIA
929001	FRANCHISE REQMTS-CR
929002	ELEC USED-ELEC DEPT
929003	GAS USED-GAS DEPT
929004	ELECTRICITY USED - OTHER DEPARTMENTS
929005	ELECTRICITY USED BY ELECTRIC DEPARTMENT - ODP
929006	KWH SOURCES - ODP - (STAT ONLY)
929007	ODP FREE LIGHTING
930101	GEN PUBLIC INFO EXP
930191	GEN PUBLIC INFO EXP - INDIRECT
930201	MISC CORPORATE EXP
930202	ASSOCIATION DUES
930203	RESEARCH WORK
930207	OTHER MISC GEN EXP
930223	SUSPENSE - PPL
930250	BROKER FEES
930272	ASSOCIATION DUES - INDIRECT
930274	RESEARCH AND DEVELOPMENT EXPENSES - INDIRECT
930277	OTHER MISC GEN EXP - INDIRECT
930902	ASSOCIATION DUES - INDIRECT
930903	RESEARCH WORK - INDIRECT
930904	RESEARCH AND DEVELOPMENT EXPENSES
930907	OTHER MISC GEN EXP - INDIRECT
931004	RENTS-CORPORATE HQ
931100	RENTS-OTHER
931900	I/C JOINT USE RENT EXPENSE-INDIRECT
935101	MTCE-GEN PLANT
935203	SOFTWARE MTCE AGREEMENTS
935391	MTCE-COMMUNICATION EQ - INDIRECT
935401	MTCE-OTH GEN EQ
935402	MAINT. OF NON-BONDABLE GENERAL PLANT
935403	MNTC BONDABLE PROPERTY
935488	MTCE-OTH GEN EQ - INDIRECT
999999	GL TO PA INTERFACE

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(k)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

The independent auditor's annual opinion report, with any written communication from the independent auditor to the utility which indicates the existence of a material weakness in the utility's internal controls.

Response:

KU has not received any written communication from its auditor that there are any material weaknesses in KU's internal controls.

See attached.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Sole Stockholder of Kentucky Utilities Company

We have audited the accompanying balance sheet of Kentucky Utilities Company as of December 31, 2011, and the related statements of income, comprehensive income, cash flows, and equity for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Kentucky Utilities Company at December 31, 2011 and the results of its operations and its cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Louisville, Kentucky
February 28, 2012

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(l)
Sponsoring Witness: Valerie L. Scott

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission or Federal Communication Commission audit reports.

Response:

The most recent Federal Energy Regulatory Commission ("FERC") audit report relating to KU's electric business is attached. The FERC is currently performing a periodic audit of (a) certain FERC accounting, affiliate transactions, reporting, records retention and associated areas and (b) certain FERC transmission formula rates relating to KU and affiliated companies for the period January 1, 2010 through December 31, 2011. Such audit may be completed in late 2012 or during 2013. The Federal Communications Commission has not conducted an audit of KU, and, therefore, no such audit reports exist.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. PA05-9-000
July 17, 2006

Michael S. Beer
Vice President, Federal Regulation and Policy
LG&E Energy Services, Inc.
220 West Main Street
Louisville, KY 40202

Dear Mr. Beer:

1. The Division of Audits within the Office of Enforcement (OE) has completed the audit of LG&E Energy LLC (LG&E) for the period from January 1, 2003 to December 31, 2005. The enclosed audit report explains our audit findings and recommendations.

2. On June 29, 2006, you notified us that LG&E agreed with our audit findings and recommendations. I hereby approve and direct the recommended corrective actions. A copy of your response is included as an Appendix to this audit report.

3. LG&E should file an implementation plan within 30 days of the date of this letter order and submit quarterly filings describing LG&E's progress completing each corrective action, including dates it has completed each corrective action. The filings should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

4. The Commission delegated the authority to act on this matter to the Director of OE under 18 C.F.R. § 375.314 (2006). This letter order constitutes final agency action. Your Company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2006).

5. This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention.

6. I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Bryan K. Craig, Director, Division of Audits at (202) 502-8741.

Sincerely,

Susan Court

Susan J. Court
Director
Office of Enforcement

Enclosure

FEDERAL ENERGY REGULATORY COMMISSION

Audit Period: January 1, 2003 through December 31, 2005

Audit of Code of Conduct, Standards of Conduct, Market-Based Rate Tariff, and MISO's Open Access Transmission Tariff at LG&E Energy LLC

Audit Report

OFFICE OF ENFORCEMENT
DIVISION OF AUDITS

Docket No. PA05-9-000 **Date: July 17, 2006**

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY

A. Overview

The Office of Enforcement (OE)[1] has completed an audit of the operations of LG&E Energy LLC (LG&E).[2] For purposes of the audit, the relevant parts of LG&E's corporate structure included:

- The two utilities (Louisville Gas & Electric Company and Kentucky Utilities Company), each of which operates a system control center,
- LG&E's service company (LG&E Energy Services, Inc.), and
- LG&E's Marketing and Energy Affiliates, including LG&E's wholesale merchant function (WMF) and its affiliated power marketers [3]; LG&E's principal affiliated power marketer during the audit period was LG&E Energy Marketing, Inc. (LEM).

The audit covered the period from January 1, 2003 through December 31, 2005, and focused on LG&E's compliance with:

- LG&E's Code of Conduct, which requires the physical, operational, and functional separation of LG&E's WMF and its affiliated power marketers,
- The Commission's Standards of Conduct under Order No. 2004 and 18 C.F.R. Part 358 (2005), which requires the transmission function to operate independently from LG&E's energy marketing operations,
- LG&E's market-based rate tariff, and

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[1] On April 16, 2006, the Office of Market Oversight and Investigations changed its name to the Office of Enforcement.

[2] On December 1, 2005, LG&E Energy LLC announced it changed its name to E.ON US.

[3] *LG&E Power Mktg., Inc.*, 68 FERC ¶ 61,247 (1994); *modified on other grounds*, 69 FERC ¶ 61,153 (1994). LG&E Power Mktg.'s name was changed to LG&E Energy Marketing Inc. (LEM). *See* Notice of Name Change, Docket No. ER97-3418-000 (filed June 24, 1997).

- Midwest ISO (MISO) Open Access Transmission Tariff (OATT) §28.6 Restrictions on Use of Service; §30.1 Designation of Network Resources; §30.4 Operation of Network Resources; and §30.7 Limitation on Designation of Network Resources.

B. Summary of Compliance Findings

Our audit findings are based on materials provided by LG&E in response to data requests, interviews with LG&E staff members, site visits, and a review of publicly available documents. LG&E has been very cooperative throughout the audit.

Based on our examination of the Code of Conduct, Standards of Conduct, Market-Based Rate Tariff, and MISO's OATT at LG&E, we identified nine areas of non-compliance.

<u>Code of Conduct Compliance</u>

- *Functional, Physical, and Operational Separation of LG&E's WMF and Affiliated Power Marketer*: LG&E's WMF and its principal affiliated power marketer (LEM) were not functionally, physically, and operationally separate to the maximum extent practical, as required by LG&E's Code of Conduct. Both WMF and LEM functionally reported to the same company officer and LEM shared physical facilities with WMF traders and with mid-office and back-office functions for the WMF. WMF and LEM operationally shared a telephone recording system to capture trading and dispatch conversations.

- *Sharing of Market Information*: LG&E's WMF shared market information with its principal affiliated power marketer (LEM) through presentations at joint staff meetings, in violation of LG&E's Code of Conduct. Also, the password access controls to the shared Energy Management System (EMS) were inconsistent with LG&E's password security policy.

- *Posting of Information on Sales to Affiliates at Market-Based Rates*: LG&E was required to post on an electronic bulletin board (EBB) information on energy sales at market-based rates from its WMF to its affiliated power marketer (LEM). LG&E's Code of Conduct required the price of such sales to be no lower than the rate charged to non-affiliates, and required simultaneous postings on an EBB of WMF's offers to sell to LEM and WMF's actual sales to LEM. Our review of LG&E's archived EBB postings disclosed that LG&E's EBB was not accessible to non-affiliated market participants for a period of time, and the information that LG&E posted on the EBB was not consistent with the requirements in LG&E's Code of Conduct.

Docket No. PA05-9-000

Standards of Conduct Compliance

- *Disclosures of Transmission and Customer Information*: LG&E transmission employees improperly disclosed non-public transmission and customer information to employees of its WMF that was not contemporaneously available to the public, and failed to post in a timely manner the information disclosure on OASIS: (1) on at least three occasions, LG&E transmission employees disclosed real-time transmission system status information to LG&E Energy and Marketing affiliate employees during telephone calls concerning generation re-dispatch; (2) on at least one occasion, LG&E made transmission expansion planning information available to marketing employees; and (3) on a monthly basis through February 2005, a transmission employee sent e-mails to a marketing employee containing load data of third-party customers.

- *Standards of Conduct Training*: The scope of LG&E's Standards of Conduct training program was inconsistent with Commission regulations and with LG&E's training implementation plans. More than one year after the effective date of Order No. 2004, LG&E had failed to provide Standards of Conduct training for several hundred of the employees LG&E was required to train.

- *Controls Used to Limit Access to System Control Centers*: LG&E did not follow its posted implementation procedures to control and track access by the employees of its Marketing and Energy Affiliates to LG&E's two system control centers, including the requirement that LG&E marketing employees obtain permission from the Chief Compliance Officer (CCO) before visiting the system control centers.

- *Organizational Charts*: The organizational chart postings failed to include or accurately show: detailed organizational charts for business units engaged in the sales function; the position of LG&E's Marketing and Energy Affiliates within the corporate structure; and all of the business units that are part of LG&E's service company.

- *Shared Facilities*: LG&E did not post a list of the facilities shared by the Transmission Provider and LG&E's Marketing and Energy Affiliates as required by 18 C.F.R. § 358.4(b)(2) (2005).

Market-Based Rate Tariff Compliance

- *Electric Quarterly Report Inaccuracies*: LG&E's Electric Quarterly Report (EQR) filing for the first quarter of 2005 contained inaccurate information. LG&E inaccurately reported several sales transactions from its WMF to its affiliated power marketer (LEM) and reported invalid Data Universal Numbering System (DUNS) numbers for several other customers.

C. Summary of Recommendations

Detailed recommendations are included in Sections III, IV, and V of this Audit Report that describe the compliance findings. Following is a brief summary of those recommendations. We recommend that LG&E:

- Implement its planned actions to ensure that WMF and LEM employees are functionally, physically, and operationally separate to the maximum extent practical.

- Create and implement policies and procedures to ensure that there is no exchange of market information inconsistent with LG&E's Code of Conduct, and to conduct an independent review after implementation of a new EMS system to ensure that market information (and transmission information) is not accessible to employees who should not have access to such information.

- Develop written policies and procedures regarding the use of its EBB, and develop a plan for making the EBB more accessible to non-affiliated market participants.

- Post OASIS notices for all identified disclosures of non-public transmission information. Specific recommendations include creating controls to prevent disclosure of non-public transmission and customer information as part of transmission operations, during meetings attended by transmission and marketing employees, and through e-mail exchanges of information.

- Strengthen the implementation of its training program, specifically, to develop written policies and procedures to ensure that new employees receive training, and conduct periodic reviews to ensure that all of the employees that require training are scheduled for, receive training, and are certified.

- Review and strengthen its system control center access procedures to ensure that LG&E marketing employees do not have access that differs in any way from the access available to other transmission customers.

- Revise its posted organizational charts to show the business units engaged in sales functions, the position of all Marketing and Energy Affiliates within its corporate structure, and sufficient detail to indicate that LG&E's service company is the employment mechanism for the Marketing and Energy Affiliates and the Transmission Provider.

- Revise its shared facilities postings to identify all facilities that LG&E's Marketing and Energy Affiliates share with service employees who have access to non-public transmission or customer information.

- Strengthen its written procedures to ensure that EQR filings are in compliance with Commission regulations, and to refile inaccurate EQR data identified in this Audit Report.

D. Actions Already Taken by LG&E

LG&E has already taken a number of corrective actions in response to our compliance findings to come into compliance with the Standards of Conduct and LG&E's Code of Conduct. These actions are enumerated in detail in Sections III, IV, and V of this Audit Report that describe the compliance findings.

As part of the audit scope, audit staff examined LG&E's use of network integration transmission service (NITS) for the audit period prior to April 1, 2005, the beginning of the MISO Day 2 market. After working with audit staff to perform the review of LG&E's use of NITS, LG&E committed to enhancing its "Before the Purchase System" (BPS) by creating detailed control processes to ensure its compliance with the OATT and the proper use of NITS. LG&E's BPS is a software product that determines when a bi-lateral power purchase can be reasonably expected to serve native load and can be imported using network integration transmission service. LG&E's BPS system provides traders a systematic process for determining if a purchase should be imported using NITS before purchases are made and scheduled. The BPS helps ensure LG&E's compliance with the Commission's approved uses for NITS.

E. Implementation Plan

We recommended that LG&E submit an implementation plan to the audit staff for our approval detailing LG&E's plans to comply fully with the findings and recommendations in this Audit Report. The implementation plan should describe the actions LG&E has already taken, and will take, that are consistent with and complementary to any future structural and organizational changes that LG&E may undertake.

The implementation plan should be submitted within 30 days of issuance of a Final Audit Report in this docket. In addition, LG&E shall make quarterly filings updating the audit staff of its progress on implementing the plan. The filings shall be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

II. INTRODUCTION

A. Objectives

The overall audit objectives were to determine compliance with:

- LG&E's Code of Conduct, which requires the physical, operational, and functional separation of the utilities' WMF and its affiliated power marketers.

- The Commission's Standards of Conduct under Order No. 2004 (and prior to September 22, 2004, under Order No. 889[4]), which requires a Transmission Provider's employees engaged in transmission system operations to function independently from employees of its Marketing and Energy Affiliates.[5] Standards of Conduct compliance was also evaluated against LG&E's own implementation procedures.[6]

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[4] *Open-Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct*, Order No. 889, 61 FR 21737 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles ¶ 31,035 (Apr. 24, 1996); *order on reh'g*, Order No. 889-A FR 12484 (March 14, 1997), FERC Stats. & Regs., Regulations Preambles ¶ 31,049 (March 4, 1997).

[5] *Standards of Conduct for Transmission Providers*, Order No. 2004, 68 FR 69134 (Dec. 11, 2003), FERC Stats. & Regs., Regulations Preambles ¶ 31,155 (Nov. 25, 2003), *order on reh'g*, Order No. 2004-A, 69 FR 23562 (Apr. 29, 2004), FERC Stats. & Regs., Regulations Preambles ¶ 31,161 (April 16, 2004), *order on reh'g*, Order No. 2004-B, 69 FR 48371(Aug. 10, 2004), FERC Stats. & Regs., Regulations Preambles ¶ 31,166 (Aug. 2, 2004), *order on reh'g*, Order No. 2004-C, 70 FR 284 (Jan. 4, 2005), FERC Stats. & Regs., Regulations Preambles ¶ 31,172 (Dec. 21, 2004), order on reh'g, Order No. 2004-D, 110 FERC ¶ 61,320 (2005), *appeal pending*, (D.C. Circuit Docket Nos. 04-1178, et al.)

[6] "Joint Written Procedures Implementing Standards of Conduct for Transmission Providers as Adopted by the Federal Energy Regulatory Commission in Order No. 2004, Effective September 22, 2004" (hereinafter referred to as LG&E's posted implementation procedures). We found this document on April 5, 2005, posted on http://lgeenergy.com/regulatory/lgeku_compliance_procedures.pdf.

- LG&E's market-based rate tariff.[7]

- The provisions of the MISO OATT.[8]

For purposes of evaluating compliance with the Standards of Conduct, this audit focuses primarily on the period from September 22, 2004, the effective date of Order No. 2004, to December 31, 2005. For purposes of evaluating compliance with Code of Conduct, market-based rate tariff and MISO's OATT requirements, this audit focuses primarily on the period from January 1, 2003 to December 31, 2005.

B. Scope and Methodology

The OE has completed an audit of the operations of LG&E. As part of the audit, OE conducted selective tests on data to determine LG&E's compliance with the Standards of Conduct, Code of Conduct, market-based rate tariff, and MISO's OATT requirements. Selective tests included those necessary to verify the accuracy of required informational postings on LG&E's OASIS, the effectiveness of written procedures and internal controls related to the Standards of Conduct, and compliance with all the provisions of the Standards of Conduct, LG&E's Code of Conduct, LG&E's market-based rate tariff, and the MISO OATT.

Additionally, we reviewed physical and electronic security over transmission operations and information. We discussed with LG&E personnel matters related to the corporate structure, Energy and Marketing Affiliates, local and wide area networks, shared functions, and the Standards of Conduct training received. We reviewed e-mail records and recorded conversations between LG&E's transmission operations and its Energy and Marketing Affiliates.

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[7] *Louisville Gas & Elec. Co.*, 85 FERC ¶ 61,125 (1998) (accepting for filing joint market-based rate tariff of LG&E and KU, FERC Electric Tariff, Original Volume No. 2); *LG&E Operating Cos.* Docket No. ER99-1623-000. Letter Order, Jun. 4, 1999 (accepting revised tariff sheets to Original Volume No. 2 permitting limited sales to certain affiliates); *Louisville Gas & Elec. Co.*, Letter Order, Docket No. ER02-1077-000, Apr. 16, 2002 (accepting "short form" market-based rate tariff as Original Volume No.3).

[8] *Midwest Independent Transmission System Operator, Inc., et al.*, 84 FERC ¶ 61,231 (1998); *order on reconsideration*, 85 FERC ¶ 61,250 (1998); *order on reh'g*, 85 FERC ¶ 61,372 (1998); *order on compliance filing*, 87 FERC ¶ 61,085 (1999).

III. CODE OF CONDUCT FINDINGS AND RECOMMENDATIONS

1. Functional, Physical and Operational Separation of LG&E's WMF and Affiliated Power Marketer

LG&E's WMF and its principal affiliated power marketer (LEM) were not functionally, physically and operationally separate to the maximum extent practical, as required by LG&E's Code of Conduct. The WMF and LEM were functionally within the same LG&E business unit, and reported to the same company officer; the WMF and LEM shared physical facilities without strong controls to prevent information sharing; and the WMF and LEM shared a telephone recording system that provided LEM employees access to operational information such as WMF trading activities.

Pertinent Guidance

Section 3 of LG&E's Code of Conduct states that "(t)o the maximum extent practical, employees of the Utilities [*i.e.*, LG&E's WMF] who operate the Utilities' systems or engage in power purchasing or selling on behalf of the Utilities will be physically, operationally, and functionally separate from employees of the Marketers performing power marketing activities."[9]

Discussion

Collectively, the lack of functional, physical, and operational separation between WMF and LEM precluded LG&E from operating these entities as separate business units to the maximum extent practical as required in Section 3 of LG&E's Code of Conduct.

Functional Separation Between WMF and LEM

LG&E's WMF and its primary affiliated power marketer (LEM) were not functionally separate to the maximum extent practical since they functionally reported to the same company officer, *i.e.*, the Senior Vice President (SVP) of Energy Marketing. The employees of the two trading operations attended periodic meetings together, convened by the SVP of Energy Marketing. As described in the compliance finding "Sharing of Market Information" which follows next in this Audit Report, general market

[9] *LG&E Power Mktg., Inc.*, 68 FERC ¶ 61,247 (1994); *modified on other grounds*, 69 FERC ¶ 61,153 (1994). LG&E Power Mktg.'s name was changed to LG&E Energy Marketing Inc. (LEM). *See* Notice of Name Change, Docket No. ER97-3418-000 (filed June 24, 1997).

information, as well as specific market information about WMF and LEM trading operations was discussed at these meetings.

According to the job description of the SVP Energy Marketing, the occupant of the position was responsible for establishing the strategic direction and management of the energy marketing, fuel procurement and trading activities for the WMF and also directs the optimization of the corporation's energy-related integrated gross margin. This job description indicates that the SVP Energy Marketing is expected to coordinate WMF and LEM activities to provide a greater return for the LG&E corporate family. This lack of functional separation between WMF and LEM was inconsistent with LG&E's Code of Conduct.

Physical Separation Between WMF and LEM

LG&E lacked sufficient physical barriers to ensure that the WMF's non-public market information was not shared with LEM. WMF operations and LEM operations were both located on the seventh floor of LG&E's headquarters building. Sharing a floor is not a violation of the Code of Conduct, as long as there are sufficient controls to ensure the physical separation of employees and operations. The physical space occupied by WMF operations were secured by a card key access system. However, LEM's operations were not secured by a card key access system, and the workspace of LEM employees (with the exception of the Director of LEM) was arranged in open carrels. WMF employees passed by LEM's workspace on their way to and from a conference room shared by the two trading operations, and the employees shared common facilities such as kitchen and restrooms. WMF and LEM employees frequently held discussions on the LEM trading floor, but LG&E asserted and the employees we interviewed confirmed that the information exchanged between WMF and LEM traders was not prohibited information—it was limited to public information regarding the market and market information about LEM.

The seventh floor also contained LG&E's risk management and energy accounting functions, both of which have access to WMF information. The risk management and energy accounting offices were not protected, e.g., through card key access, against entry by LEM personnel.

Operational Separation with Respect to Recorded Phone Calls

LG&E recorded phone calls of its traders and dispatchers for both the WMF and LEM functions on two RACAL digital tape recorder machines. Each machine recorded calls made by employees of both organizations on digital tapes. Each digital tape contained approximately 60,000 to 75,000 calls or about 21-28 days worth of recorded calls containing conversations made by both WMF employees and LEM employees.

Each call was identified by date, time, and channel number which corresponded to a person or workstation. A recorded call varied in length from a few seconds to several minutes.

The two RACAL recorder machines and tapes were located on the seventh floor of LG&E's headquarters building in a locked room with access controlled by a LEM administrative employee. The LEM administrative employee provided access to specific tapes when WMF or LEM employees requested access to the tapes. The LEM administrative employee initially set up the machine to a channel, date and time, then instructed the WMF and LEM employees how to operate the machine to find other calls. The listening process involved searching and listening to the tape on a trial and error basis until the call was identified. The LEM administrative person did not remain in the room at all times while the WMF or LEM employees listened to the tapes, and these employees had the opportunity to access the entire contents of a tape containing both WMF and LEM recordings.

Recommendations

We recommend that LG&E:

1. Take all appropriate actions necessary to ensure that WMF employees and LEM employees are functionally and physically separate to the maximum extent practical, as required under LG&E's Code of Conduct.

2. Implement procedures to ensure that authorized access to the tape recordings are properly documented.

3. Implement procedures to separate tape recordings for WMF and LEM channels.

4. Implement controls to provide access to only one tape recording machine when WMF or LEM personnel are authorized to listen to tapes and implement controls to prevent unauthorized access to channels of historical tapes which contain recorded conversations of both WMF and LEM channels.

5. LG&E shall submit all procedures and controls to OE for approval within 30 days of issuance of a Final Audit Report in this docket.

Actions Already Taken by LG&E

After we discussed our concerns with the lack of physical separation between LEM and WMF, LEM physically moved from the seventh floor to the fourth floor of the LG&E building and LEM employees no longer have access to the seventh floor as of March 31, 2006.

LG&E also began maintaining a written log of all access to tapes and revamped its recording system so that now WMF and LEM employee conversations are recorded on separate tapes and machines. We verified that this change had been made during our site visit in October 2005. However, LG&E must still implement access controls to the tapes when WMF or LEM employees listen to tapes containing recorded conversations of both WMF and LEM channels. Also, LG&E must implement physical access controls to the recording machines if WMF or LEM employees are provided access to the secure room to listen to tapes.

The corrective actions do not solve the functional separation problem between WMF and LEM. LG&E will submit a plan to functionally separate WMF and LEM.

2. Sharing of Market Information

LG&E's WMF shared market information with LEM through presentations at joint staff meetings, in violation of LG&E's Code of Conduct. Also, password access controls to the shared Energy Management System (EMS) were insufficient and inconsistent with LG&E's password security policy.

Pertinent Guidance

Section 4 of LG&E's Code of Conduct states that "(n)o employee of the Utilities will share market information with any employee of the Marketers unless all such information is simultaneously made available to the public. The policy will not apply to market information known to be publicly available, or to market information disclosed to employees of the Marketers or the Utilities who are engaged in support functions, including human resources, information resources, data processing, finance, legal, accounting and other support personnel who do not participate in directing, organizing and executing the day-to-day business decisions of the wholesale merchant or generation functions of the Utilities or the Marketers, *provided* that such employees are prohibited from acting as conduits to pass market information obtained from the Utilities to the Marketers."[10] (emphasis in original.)

LG&E's password security policy requires a password for each employee accessing LG&E's Local Area Networks (LAN) and Wide Area Networks (WAN).

Discussion

Joint Staff Meetings Between WMF and LEM

LG&E's WMF shared non-public market information with LEM through presentations at joint staff meetings, in violation of LG&E's Code of Conduct. The monthly trading meetings normally took place during the last week of each calendar month. In addition to the SVP of Energy Marketing, the managers of WMF and LEM attended, as well as staff from WMF and LEM, plus staff from the Market Analysis, Trading Controls, Operations Analysis and Fuels Management sections.

During the months of August, 2004 through May, 2005, the agendas of the Trading Meetings remained unchanged. The first item on the agenda was a presentation by the Manager of the WMF on the results of Regulated Off-System Sales (OSS) for the month, and how the results compared with the amount budgeted for that item. This

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[10] *Id.*

information included reforecast graphs for the calendar year-to-date, the results for the current month-to-date, the factors leading to the results (including such items as purchase power costs and transmission expenses), and a review of the profit-at-risk graph. Following this presentation by the WMF, LEM presented a report on its sales operations for the previous month and its forecasts and plans for the future.[11] Following LEM's presentation, the SVP of Energy Marketing dismissed the LEM employees from the meeting after which the WMF made additional reports about its operations and forecasts.

LG&E's Code of Conduct states that no employee of the WMF will share market information with any affiliated power marketer employee unless all such information is simultaneously made available to the public. Based on review of the agendas, and interviews with WMF personnel, we concluded that the WMF Off-System Sales' information presented at the beginning of the monthly meetings by the Manager of the WMF was WMF market information. This information was disclosed to LEM personnel present at the beginning of these meetings, a violation of LG&E's Code of Conduct.

Password Access to EMS Information

LG&E's WMF and LEM both use a shared EMS, partitioned into WMF generation data, LEM generation data, and LG&E transmission data. Password access controls to the shared EMS were insufficient and inconsistent with LG&E's password security policy. Prior to February 2004, LG&E permitted WMF and LEM users to access the EMS using separate group accounts and passwords, rather than using unique user accounts and passwords. The failure to require unique password access was contrary to LG&E's password security policy and increased the risk of inappropriate information access via the EMS. Specifically, group passwords are easier to disseminate and it is not possible to track the identity of individuals that use a group account to ensure that only those with appropriate clearance have accessed the EMS. Because WMF employees and LEM employees used group accounts and passwords, it was not possible to track individual access to specific account information.

[11] The information related to Western Kentucky Electric (WKE), LEM's sole remaining customer. In past years the information also related to LEM's contract with Oglethorpe Power Corporation (OPC).

Recommendations

We recommend that LG&E:

6. Create controls consistent with LG&E's Code of Conduct to ensure that there is no exchange of market information stemming from joint trading meetings for WMF and affiliated power marketing personnel.

7. Conduct an independent review by the internal audit department or an outside auditing firm when the new EMS is implemented in 2006 to ensure that there is no improper or unauthorized EMS screen access.

8. LG&E shall submit all controls to OE for approval within 30 days of issuance of a Final Audit Report in this docket. Also, LG&E shall submit the results of the independent review of the EMS to OE within 30 days after implementing its new EMS or issuance of a Final Audit Report in this docket, whichever is later.

Actions Already Taken by LG&E

After we discussed our concerns with LG&E about joint trading meetings between WMF and LEM, LG&E changed the agenda of the monthly trading meetings starting in June 2005. The agenda was altered so that the presentation about WMF's OSS is not made until later in the meeting, after LEM employees have left the meeting. In addition, beginning in December 2005, LG&E adopted certain process changes, including the requirement that the CCO or his designee attend all joint WMF and LEM meetings, and maintain a high-level agenda and/or minutes of each meeting.

LG&E implemented unique user accounts and passwords for its current GE/Harris EMS in February 2004. LG&E is currently developing, installing and testing a new EMS that should be operational in 2006.

3. Posting of Information on Sales to Affiliates at Market-Based Rates

LG&E's EBB was inaccessible to non-affiliated market participants, and the information on the EBB was not consistent with Commission requirements. The EBB would have been difficult for non-affiliate market participants to find, given that for some period of time it was located on a website of an LG&E affiliate that was not a party to affiliate sales. In addition, for some period of time it may not have been accessible over the internet. Moreover, the information and timing on offers to sell and actual sales to affiliates were not consistent with the specific requirements in LG&E's Code of Conduct.

Pertinent Guidance

On January 29, 1999, LG&E petitioned the Commission for blanket authority to authorize the Utilities, *i.e.*, LG&E's WMF, to sell energy at market-based rates to their power marketing affiliates. Acknowledging the Commission's concern about protecting captive ratepayers from subsidizing affiliate marketing operations, LG&E committed to adopt the safeguards the Commission approved in Detroit Edison Company.[12]

To implement these safeguards, LG&E amended its Code of Conduct to add the following requirements: "The Utilities will sell power to the Marketers at a rate that is no lower than the rate the Utilities charge to nonaffiliates; simultaneously with making an offer to sell power to the Marketers, the Utilities will make the same offer to nonaffiliates through a posting on their electronic bulletin board ("EBB"); and simultaneously with the striking of a power sales transaction with the Marketers, the Utilities will post the actual price paid on their EBB."[13]

Discussion

Accessibility of EBB Information to Market Participants

We sought to create a timeline for LG&E's EBB. LG&E's WMF made energy sales at market-based rates to LEM from 1999 through the Spring of 2005, but we could not confirm that the information posted on such sales was accessible to market participants. Based on the documentation provided to us by LG&E:

- From 1999 through December 2003, the sales information was posted on an EBB website for LG&E Power, one of LG&E's affiliated power marketers.

[12] 80 FERC ¶ 61,348 (1997).

[13] Docket No. ER99-1623-000, Compliance Filing of Louisville Gas and Electric Company and Kentucky Utilities Company, filed March 4, 1999, at 2.

- In December 2003, the EBB containing the sales information migrated from the LG&E Power website to the LG&E Energy website.

- In April 2005, LG&E provided us the website address for the EBB, http://apps.lgeenergy.com/fercgen/gensales.asp. When we tried to access the EBB at this address, the page would not display. We subsequently asked LG&E how to access the EBB. On May 4, 2005, the internet address on LG&E Energy's website worked. We asked LG&E when this link to the EBB was made operational; LG&E informed us that it was made operational on May 1, 2005.

LG&E stated that other than LG&E's filing made in 1999 revising its Code of Conduct to post affiliate transactions on an EBB, it could not recall any occasions where it publicized the existence of the EBB. LG&E, however, could not recall a single instance when a market participant had inquired about any posting on the EBB.

Posted Offers to Sell on the EBB

LG&E's Code of Conduct required LG&E to make a simultaneous offer on the EBB to sell to non-affiliates the same product it was offering to sell to its affiliate. We concluded that the posting of offers to sell on the EBB were not consistent with the requirements of LG&E's Code of Conduct.

We reviewed archived EBB data for the audit period. Typically, each month on the first of the month, LG&E's WMF would post on the EBB an offer to sell a block of energy on an hourly basis. This monthly posting was at an asking price of $12/MWh for virtually every month that a monthly offer was posted. LG&E stated that the asking price was set at $12/MWh in order to induce counterparties to enter negotiations to purchase from LG&E's WMF.

We reviewed LG&E's variable costs on a generator-by-generator basis. Although prices of coal and other inputs changed over the course of the period that LG&E posted offers on the EBB, we concluded that had LG&E sold energy at $12/MWh during any hour during which it posted an asking price of $12/MWh, it would have been selling energy at a price less than its incremental cost. Moreover, our review of the EBB shows that WMF never sold energy to LEM at a price of $12/MWh or less. LG&E's strategy of posting an asking price of $12/MWh did not satisfy the Code of Conduct requirements to simultaneously offer hourly energy to non-affiliated market participants at the same price that it would offer such energy to its affiliate.

Prices of Affiliate Sales

We evaluated whether the prices at which WMF sold energy to LEM were consistent with the requirements of LG&E's Code of Conduct, *i.e.*, at a rate that is no lower than the rate that WMF sold to non-affiliated buyers. LG&E had no written procedures or other controls for its WMF traders to follow to determine an appropriate market price at which the WMF would sell to LEM. LG&E's WMF traders established the market price through telephone queries and broker quotes prior to negotiating a next-hour energy sale to LEM. We listened to recorded phone calls during hours in which WMF traders sold energy to LEM. We found no evidence that WMF traders sold energy to LEM at prices less than the market price in accordance with LG&E's Code of Conduct. However, when we reviewed the recorded phone calls, we found that WMF traders did not generally employ strong controls to establish the market price.

EBB Postings in 2001

We had specific concerns whether LG&E was properly using the EBB to post offers and sales from WMF to LEM to support a long-term sales obligation LEM had with Morgan Stanley, specifically affiliate sales in 2001. Based on the data provided to us by LG&E, we found the following EBB posting errors:

- WMF sold to LEM 50 MWh of energy during each off-peak hour during the month of May 2001 without posting offers or transactions on the EBB. We estimated these energy sales in May 2001 to total nearly 20,000 MWh, and to have generated revenues of approximately $500,000.

- LG&E failed to post on the EBB offers or transactions when WMF sold energy to LEM to support LEM's sales to Morgan Stanley for an additional 10 days during calendar year 2001.

Recommendations

We recommend that LG&E:

9. Develop written procedures regarding the use of its EBB. Specifically, the written procedures should address how LG&E will ensure that the price at which it sells energy to its affiliate is no lower than the price at which it sells to non-affiliates, and how LG&E will post offers and sales on the EBB to make the information available to other market participants to demonstrate that its affiliate sales are at non-preferential prices.

10. Develop a plan to ensure that the EBB is fully accessible, and that market participants know where to find the EBB on the LG&E website.

11. LG&E shall submit all procedures and plans to OE for approval within 30 days of issuance of a Final Audit Report in this docket.

Actions Already Taken by LG&E

We had numerous discussions with LG&E about the accessibility and effectiveness of its EBB postings. As of January 2006, LG&E had a link from its corporate website to the EBB. In addition, LG&E presented us plans for making the information posted on the EBB consistent with LG&E's Code of Conduct. LG&E has agreed to finalize these plans and to develop written procedures to guide trading staff on the use of the EBB within 30 days of the issuance of a Final Audit Report in this docket.

IV. STANDARDS OF CONDUCT FINDINGS AND RECOMMENDATIONS

4. Disclosures of Transmission and Customer Information

LG&E transmission employees improperly disclosed transmission and customer information to employees of its WMF that was not contemporaneously available to the public, and failed to post the information disclosure on OASIS.

Pertinent Guidance[14]

A Transmission Provider must ensure that any employee of the Marketing or Energy Affiliate is prohibited from obtaining information about the Transmission Provider's transmission system through access to information not posted on the OASIS or Internet website or that is not otherwise also available to the general public without restriction.[15]

An employee of the Transmission Provider may not disclose to its Marketing or Energy Affiliates any information concerning the transmission system of the Transmission Provider or the transmission system of another through non-public communications conducted off the OASIS or Internet website, through access to information not posted on the OASIS or Internet website that is not contemporaneously available to the public, or through information on the OASIS or Internet website that is not at the same time publicly available.[16]

A Transmission Provider may not share any information, acquired from non-affiliated transmission customers or potential non-affiliated transmission customers, or developed in the course of responding to requests for transmission or ancillary service on the OASIS or Internet website, with employees of its Marketing or Energy Affiliates,

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[14] Some of the incidents supporting this finding occurred under the former Order No. 889 Standards of Conduct requirements, *i.e.*, Part 37 requirements pre-September 22, 2004, Part 358 requirements thereafter. There are no significant differences in the specific requirements of Part 37 and Part 358 that bear upon the finding that LG&E improperly disclosed transmission and customer load information.

[15] 18 C.F.R. § 358.5(a)(2) (2005).

[16] 18 C.F.R. § 358.5(b)(1) (2005).

except to the limited extent information is required to be posted on the OASIS or Internet website in response to a request for transmission service or ancillary services.[17]

If an employee of the Transmission Provider discloses information in a manner contrary to the requirements of sections 358.5(b)(1) and (2), the Transmission Provider must immediately post such information on the OASIS or Internet Web site.[18]

Also, LG&E's posted implementation procedures provided that "any person with knowledge or concerns regarding activities that may have resulted, or could result, in a violation of the Standards of Conduct and/or Standards of Conduct Written Procedures is strongly encouraged, expected, and required to report them to the CCO without delay."

Discussion

Disclosures of Transmission Information by Telephone

On at least three occasions, once in May, 2004 and twice in November, 2004 LG&E transmission employees disclosed transmission line loading and operating status information to LG&E generation dispatchers during the course of generation re-dispatch events. LG&E's generation dispatch function is organizationally and functionally within its marketing business unit; therefore generation dispatch personnel are Energy and Marketing Affiliate employees.[19] In each instance, the transmission information was disclosed through non-public communication.

LG&E identified three calls involving the disclosure of non-public transmission information relating to the loading of, line operational status, or redispatch or switching relief options for the 345 kV line Smith – Hardin County; 138 kV line Paddys Run – Paddys West; and 138 kV line Cane Run 6 – Cane Run Switching. LG&E acknowledged that the disclosed transmission information was not otherwise available to market participants through OASIS or other sources at the time that it was disclosed. We

[17] 18 C.F.R. § 358.5(b)(2) (2005).

[18] 18 C.F.R. § 358.5(b)(3) (2005).

[19] The manager of generation dispatch reports to the Director of Trading who reports to the Senior Vice President for Energy Marketing. The generation dispatch desk is on the trading floor, located next to the workstation used by LG&E's real-time traders. Moreover, on occasion, LG&E's generation dispatchers talked to potential energy buyers and sellers on the phone and made trades if no one else on the trading floor was available to do so.

reviewed the disclosed information and determined that its disclosure to generation dispatch personnel was not necessary to ensure reliability and hence is not exempt under 18 C.F.R. § 358.5(b)(6) (2005). LG&E confirmed that the transmission information disclosed was not shared with traders, and there were no trades made by generation dispatchers in the hours subsequent to the disclosure of transmission information.

LG&E's generation dispatchers received Standards of Conduct training, and had available to them LG&E's Standards of Conduct implementation procedures, which required that improper disclosures of non-public transmission information be reported to the CCO. The generation dispatch employee did not disclose the incidents to anyone, including the CCO, so the disclosures were not posted on LG&E's OASIS after they occurred.

Disclosure of Transmission Information at a Meeting Attended by Transmission and Marketing Employees

During the audit period, we identified one meeting in which transmission personnel and marketing personnel were present at which LG&E transmission personnel disclosed non-public information regarding the status of two transmission projects. LG&E did not subsequently post the disclosures on its OASIS. At a Long Term Planning meeting that the SVP of Energy Marketing attended, the Director of Transmission discussed two transmission projects, providing information that was not publicly available in the Midwest ISO Transmission Expansion Plans ("MTEP"). These Projects were a 138/69kV transformer at VA City – Clinch River, which was a new interconnection tie-line between LG&E and American Electric Power Company, Inc., and a 138/69kV transformer at Paris substation, which was a reinforcement of the existing tie-line between LG&E and East Kentucky Power Cooperative. Each of the above two proposed projects would increase the transmission capacity between LG&E and the adjacent control area. LG&E did not post in a timely manner the disclosure on the OASIS after it occurred. We found no evidence that LG&E's Energy or Marketing Affiliates traded on this information.

Disclosure of Customer Load Data by E-Mail

On the first of the month, on a monthly basis through February 2005, a transmission employee e-mailed a marketing employee specific, non-public customer load information and failed to post in a timely manner the disclosures on OASIS.[20] Prior

[20] In *Allegheny Power Service Corporation et al, (Allegheny)* the Commission stated that the WMF may have access to control area load and not the specific load of third-party transmission customers within the same control area. *See Allegheny,* 84 FERC ¶ 61,131 at 61,729 (1998).

to August 1, 2003, the e-mails identified the date, time and LG&E's control area peak load, and load for the same date and time for LG&E, Hoosier Energy, Owensboro Municipal Utilities, Tennessee Valley Authority, and East Kentucky Power Cooperative. Beginning August 1, 2003 and continuing through February 1, 2005, the e-mails added the customer's monthly energy usage, peak load and load factor.[21] LG&E acknowledged that this information was not publicly available. Knowledge of specific third-party load information could have been used to the advantage of LG&E's traders, although we found no evidence that this occurred.

Recommendations

We recommend that LG&E:

12. Post OASIS notices for all of the disclosures of non-public transmission information by LG&E's transmission function employees identified in this Audit Report. These postings should include the date, time, type of information disclosed, and other pertinent information.

13. Create and implement controls to prevent prospectively the disclosure of non-public transmission information to marketing employees performing generation dispatch functions and controls to ensure that any subsequent disclosure(s) are posted on OASIS consistent with Commission regulations. Such controls need to emphasize LG&E's policy that all concerns related to the Standards of Conduct should be brought to the attention of the CCO.

14. Create and implement controls to prevent prospectively the disclosure of non-public transmission information during meetings attended by both transmission and marketing employees, and controls to ensure that any subsequent disclosure(s) are posted on OASIS consistent with Commission regulations. Such controls need to emphasize LG&E's policy that all concerns related to the Standards of Conduct should be brought to the attention of the CCO.

15. Perform a review of all transmission and customer information shared through e-mail distribution in order to ensure that such information is not inappropriately shared with LG&E's Marketing and Energy Affiliate employees.

[21] The load factor represents the ratio of the average load over a designated period of time to the peak load occurring during that period.

16. LG&E shall submit all controls and the results of its email distribution review to OE for approval within 30 days of issuance of a Final Audit Report in this docket.

Actions Already Taken by LG&E

We discussed our concerns about the disclosure of transmission and customer information. LG&E informed us that it is developing process changes for addressing our concerns on a prospective basis, and that ultimately the process changes would be converted into formal written policies within 30 days of issuance of a Final Audit Report in this docket.

5. Standards of Conduct Training

LG&E's Standards of Conduct training program was inconsistent with Commission regulations and LG&E's own training implementation plans—more than one year after the effective date of Order No. 2004 (*i.e.*, 9/22/04), LG&E had failed to provide Standards of Conduct training for several hundred of the employees LG&E was required to train.

Pertinent Guidance

Order No. 2004 codified the training requirement as follows: "Transmission Providers shall train officers and directors as well as employees with access to transmission information or information concerning gas or electric purchases, sales, or marketing functions. The Transmission Provider shall require each employee to sign a document or certify electronically signifying that s/he has participated in the training." [22] Moreover, training was to be completed by the implementation date of Order No. 2004: "Each Transmission Provider must be in full compliance with the standards of conduct by September 22, 2004."[23]

Order No. 2004 required a Transmission Provider to post its implementation procedures on its OASIS or website, specifically requiring that Transmission Providers "must explain…whether employees have been offered training on the standards of conduct, and whether employees are required to read and sign acknowledgement forms."[24] LG&E's posted implementation procedures have limited detail on its training program. LG&E directed us to an internal company training plan, which states (in part):

- All affected Company Personnel as well as employees of Energy and Marketing Affiliates (*i.e.*…except clerical, maintenance and field personnel) shall receive *Standards of Conduct* training prior to the September 22, 2004 implementation date.
- The initial *Standards of Conduct* training shall be conducted through interactive training programs developed and prepared by the Edison Electric Institute.[25]

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[22] 18 C.F.R. § 358.4(e)(5) (2005).

[23] 18 C.F.R. § 358.4(e)(2) (2005).

[24] FERC Stats. & Regs, Regulations Preambles ¶ 31,155 at P 136.

[25] "FERC Standards of Conduct, Order Nos. 2004, 2004-A, 2004-B, Training plan, August 19, 2004, Overview."

Discussion

We reviewed LG&E's training program and compared it to the requirements in Order No. 2004, as well as LG&E's training plan. We concluded that LG&E did not provide training to all employees requiring training. As of November 2005, more than one year after the September 22, 2004 implementation date of Order No. 2004, LG&E had not provided training to all employees that fall under the definition of employees who needed to be trained, *i.e.*, "employees with access to transmission information or information concerning gas or electric purchases, sales, or marketing functions."[26]

We could not determine the exact number of employees that required, but had not received, training. Employees that required Standards of Conduct training but did not receive training included:

- A handful of employees of the service company, *e.g.*, in business units such as Audit Services and Legal;
- Approximately 100 shared service employees, in business units such as Planning & Control;
- As many as 2,000 employees at LG&E-owned transmission and generation facilities, who had no training other than notification that new Standards of Conduct were in effect.[27]

We discussed with LG&E the need to determine whether the employees in these business units have access to information concerning gas or electric purchases, sales or marketing functions that would trigger a training requirement under 18 C.F.R. § 358.4(e)(5) (2005), and when they do, to ensure that they have Standards of Conduct

[26] 18 C.F.R. § 358.4(e)(5) (2005).

[27] LG&E designated these employees as field and maintenance personnel and as such did not provide training to them. But the training requirement in Order No. 2004 does not hinge on whether employees are designated as field and maintenance personnel, but rather whether an employee has access to non-public transmission information or information concerning gas or electric purchases, sales or marketing functions. LG&E told us it did not make this determination with respect to its field and maintenance personnel. As such, we could not determine how many of these employees should have received training. LG&E did not assert that these employees did not have access to non-public transmission information or information concerning gas or electric purchases, sales or marketing functions.

training. LG&E agreed to review its training program, specifically to identify the additional employees that should have received training.

Recommendations

We recommend that LG&E:

17. Strengthen the implementation of its training program to ensure that on a going-forward basis, its training program is consistent with Commission requirements and its internal training plans.

18. Develop written procedures to ensure that new employees, and transferring employees that require training, receive training.

19. Conduct a review to ensure that all of the employees that have "access to transmission information or information concerning gas or electric purchases, sales, or marketing functions…" are scheduled for training, have received training, and are certified.

20. LG&E shall submit all changes to the implementation of its training program and procedures developed to OE for approval within 30 days of issuance of a Final Audit Report in this docket. Also, LG&E shall submit the results of its review of employee access to information within 30 days after issuance of a Final Audit Report in this docket.

Actions Already Taken by LG&E

We discussed LG&E's training program with the CCO, and other LG&E officials. On November 10, 2005, LG&E submitted a letter to us outlining an enhanced training program. We reviewed LG&E's plan and found it to be consistent with the requirements of Order No. 2004, the audit findings, and our recommended remedies.

LG&E proposed to require training for all LG&E employees who fall within the definition in 18 C.F.R. § 358.4(e)(5) (2005). LG&E proposed to use the EEI computer-based Training Program, including the certification of training completion. For employees without internet access, a paper version of the training program will be used for the training. LG&E informed us on January 11, 2006, that as of that date, it had increased the number of LG&E employees who had received training by 80%, from approximately 600 employees to approximately 1100 employees.

6. Controls Used to Limit Access to System Control Centers

LG&E did not follow its posted implementation procedures to control and track access of its marketing employees to LG&E's two system control centers, including the requirement that LG&E marketing employees obtain permission from the CCO before visiting the system control centers.

Pertinent Guidance

Order No. 2004 requires that a Transmission Provider's employees engaged in transmission system operations "must function independent from employees of its Marketing and Energy Affiliates."[28] Specifically, a Transmission Provider is prohibited from permitting the employees of its Marketing or Energy Affiliates from "having access to the system control center or similar facilities used for transmission operations or reliability functions that differs in any way from the access available to other transmission customers."[29]

LG&E's posted implementation procedures provide that LG&E marketing employees must obtain permission from the CCO before visiting the system control centers: "The Chief Compliance Officer shall maintain a written record of each such decision for inspection upon request by the Commission."[30]

LG&E's posted implementation procedures also prescribe access control to the system control centers.

> The Companies shall maintain a written log book at each Transmission System Operating Center for purposes of documenting the instances in which a transmission customer, whether an employee(s) of an Energy and/or Marketing Affiliate or a representative(s) of an unaffiliated third-party, visited these facilities. The written log book should contain the: (1) name of the transmission customer; (2) the date and time of the visit; and (3) the Transmission Function Employee(s)

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[28] 18 C.F.R. § 358.2(a) (2005).

[29] 18 C.F.R. § 358.4(a)(3)(ii) (2005).

[30] "Joint Written Procedures Implementing Standards of Conduct for Transmission Providers as Adopted by the Federal Energy Regulatory Commission in Order No. 2004, Effective September 22, 2004" Section IV.A.2.b.

or other Company Personnel hosting the transmission customer; (4) whether the transmission customer is an affiliate; and (5) purpose for the visit.[31]

Discussion

LG&E operates two separate system control centers. One control center, called Waterside, is located in Louisville, KY, in a building approximately two blocks from the LG&E corporate headquarters. The other control center, called Dix Dam, is located in Burgin, KY, at the site of the Dix Dam generating facility.

LG&E used card key access to restrict direct access to its system control centers. However, we found a number of problems with the controls employed to track access of visitors (including LG&E marketing employees) to LG&E's system control centers.

CCO Permission to Visit the System Control Centers

LG&E's posted implementation procedures provide that LG&E marketing employees should submit a written request to the CCO prior to visiting either one of the system control centers. Based on our review of the Waterside log sheets, on at least five occasions, two LG&E employees with marketing or marketing-related responsibilities visited the Waterside facility after September 22, 2004.[32] The CCO told us that there was no record that marketing employees had sought permission to enter the control centers, and no record of CCO approval of such requests.

Controls on Visitors Entering the System Control Centers

The written log books controlling visitors to the system control centers were inconsistent with LG&E's posted implementation procedures. The logs did not collect some pertinent information that LG&E's implementation procedures required. Many of the entries on the log sheets were unintelligible to us, and some of these entries were unintelligible to LG&E personnel as well. As a result, we could not determine the full extent to which LG&E marketing employees (and non-affiliated transmission customers) had access to the system control centers and could not determine whether LG&E

[31] *Id.*

[32] One of the employees was the manager of the generation dispatch function, which staff established was part of the marketing function. The other was the manager of market policy—the position description for this individual said his department was responsible for monitoring and analyzing emerging electric markets and educating Energy Marketing staff on the implications of new market operations.

marketing employees had access in any way that differed from the access provided to non-affiliated transmission customers.

Access to Transmission Information Once Inside the System Control Centers

At both the Waterside and Dix facilities, a visitor standing at the door to the control centers had a line of sight into the control room, and was able to see transmission status information. This concern is heightened because of the relatively large number of LG&E marketing employees that visited a system control center. For example, our review of log sheets indicated that in the two year period prior to implementation of Order No. 2004, LG&E marketing employees may have made as many as 50 separate visits to the Waterside facility.

Recommendations

We recommend that LG&E:

21. Review and strengthen its system control center access procedures to ensure that its control procedures: (a) adhere to its own posted implementation procedures as it relates to CCO permission to visit control centers and maintenance of log books; (b) are followed by LG&E employees including the CCO and CCO designees; and (c) are certified in compliance with Order No. 2004 and LG&E's posted implementation procedures. LG&E shall submit all procedures to OE for approval within 30 days of issuance of a Final Audit Report in this docket.

22. Ensure that the entrances into the Waterside control room and Dix Dam control room are such that a visitor that enters the Waterside and Dix Dam facilities does not have a line of sight into the control rooms or to any workstations displaying data on transmission status.

Actions Already Taken by LG&E

LG&E informed us that on January 10, 2006, it revised its website to notify LG&E marketing employees that require access to the system control centers to seek written permission before each visit from the CCO. In addition, LG&E indicated that no later than January 13, 2006, the log books would be updated to conform to LG&E's posted implementation procedures, and temporary covers would be installed on all windows and doors that allow a line of sight into the system control centers.

7. Organizational Charts

LG&E's posted corporate and functional organizational charts (as of April 2005) failed to include or accurately show: detailed organizational charts for business units engaged in the sales function; the position of its Marketing and Energy Affiliates within the corporate structure; and sufficient detail to indicate that LG&E's service company is the employment mechanism for the Marketing and Energy Affiliates and the Transmission Provider.

Pertinent Guidance

The Order No. 2004 requirements for posting organizational charts provide that:

(3) A Transmission Provider must post comprehensive organizational charts showing:

(i) The organizational structure of the parent corporation with the relative position in the corporate structure of the Transmission Provider, Marketing and Energy Affiliates;

(ii) For the Transmission Provider, the business units, job titles and descriptions, and chain of command for all positions, including officers and directors, with the exception of clerical, maintenance, and field positions. The job titles and descriptions must include the employee's title, the employee's duties, whether the employee is involved in transmission or sales, and the name of the supervisory employees who manage non-clerical employees involved in transmission or sales.

Further, Order Nos. 2004-A and 2004-B requires:

If a corporation uses a service company as the employment mechanism for the Transmission Provider and its Marketing or Energy Affiliates, the organizational charts should clearly specify those circumstances. Similarly, if a corporation uses both functional and structural organizational charts for its management, the organizational charts must accurately reflect its operations....[33]

With respect to whether a detailed organizational chart is also required for a service company, the answer depends on the functions that the service company is

[33] FERC Stats. & Regs, Regulations Preambles ¶ 31,161 at P 163.

performing. If the service company is performing transmission functions, additional detail is required.[34]

Discussion

LG&E's posted several organizational charts on its website at http://lgeenergy.com/regulatory/soc.asp[35] which showed a high-level organizational structure, including the holding company which owns LG&E Energy LLC, and the legal entities under LG&E Energy LLC, including notably: the operating companies (Kentucky Utilities Company and Louisville Gas and Electric Company); the service company (LG&E Energy Services, Inc.); and an LG&E marketing affiliate (LG&E Energy Marketing Inc., or LEM).

Additional posted organizational charts showed some —but not all— of the business units of the service company. The organizational charts showed a Senior Vice President (SVP) for Energy Services, with the following direct reports: Director of Transmission; SVP for Energy Marketing; VP for Regulated Generation; and VP Power Operations for Western Kentucky Energy.

However, the only business unit for which detailed organizational charts, job titles, chains of command, and job descriptions were posted was the Director of Transmission. Such detailed information was not posted for the sales functions, *i.e.*, the SVP for Energy Marketing, VP for Regulated Generation, and VP Power Operations for Western Kentucky Energy. The sales functions under the SVP for Energy Marketing included the following business units: Director of Trading; Director of Market Analysis & Valuation; Director of Non-Utility Marketing; Manager of Operations Analysis and System Implementation; Director of Corporate Fuels & By-Products; and Director of Business Information.

In addition, the posted organizational charts did not show the relative position in the corporate structure of all of LG&E's Marketing and Energy affiliates and did not clearly indicate that LG&E's service company is the employment mechanism for its Marketing and Energy Affiliates and Transmission Provider. For example:

- LG&E's postings showed one of LG&E's Marketing and Energy Affiliates, *i.e.*, LG&E Energy Marketing Inc. (LEM), as a separate corporate entity, but did not clearly indicate that LEM employees are in the service company along with transmission function employees; and

[34] FERC Stats. & Regs, Regulations Preambles ¶ 31,166 at P 79.

[35] We reviewed the organization charts on April 5, 2005.

- LG&E's postings failed to show what position another Marketing and Energy Affiliate, LG&E Power Services LLC, occupied within the corporate structure.

Recommendations

We recommend that LG&E:

23. Post organizational charts and employee information showing the required information for all of the business units engaged in the sales function.

24. Revise its organizational chart postings to show the position of all Energy and Marketing Affiliates within the corporate structure.

25. Revise its organizational chart posting to clearly show that LG&E uses its service company as the employment mechanism for the Transmission Provider and its Energy and Marketing Affiliates. All postings shall be made within 7 business days of the issuance of a Final Audit Report in this docket, consistent with 18 C.F.R. § 358.4(b)(3)(iv) (2005).

Actions Already Taken by LG&E

After discussions with us, LG&E updated its posted organizational charts. We reviewed LG&E's organizational charts in January 2006, and found the revised organizational charts included more, but not all, of the information required under 18 C.F.R. § 358.4(b)(3) (2005).

8. Shared Facilities

LG&E did not post a list of the facilities shared by the Transmission Provider and LG&E's Marketing and Energy Affiliates as required by 18 C.F.R. § 358.4(b)(2) (2005).

Pertinent Guidance

The Commission's regulations state: "A Transmission Provider must post on its OASIS or Internet website, as applicable, a complete list of the facilities shared by the Transmission Provider and its Marketing and Energy Affiliates, including the types of facilities shared and their addresses."[36] This requires that when a Transmission Provider's Marketing and Energy Affiliates share facilities with any function of the Transmission Provider whose employees have access to transmission information, those shared facilities must be posted.[37]

Discussion

LG&E's Order No. 2004 information posted on its internet website in April 2005 stated: "At this time, no facilities are shared between the Transmission Provider and its Marketing and Energy Affiliates".

LG&E believed that it was required to post a list of shared facilities only if its transmission function shares facilities with its Marketing and Energy Affiliates. Since LG&E's transmission function is housed in two buildings (the Waterside control center and the Dix Dam control center) that otherwise do not house other LG&E business units, LG&E informed us that it did not believe it had any shared facilities that required posting.

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[36] 18 C.F.R. § 358.4(b)(2) (2005).

[37] Transmission Provider is defined as follows in 18 C.F.R. § 358.3 (2005):

(a) Transmission Provider means:

(1) Any public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce; or

(2) Any interstate natural gas pipeline that transports gas for others pursuant to subpart A of part 157 or subparts B or G of part 284 of this chapter.

(3) A Transmission Provider does not include a natural gas storage provider authorized to charge market-based rates that is not interconnected with the jurisdictional facilities of any affiliated interstate natural gas pipeline, has no exclusive franchise area, no captive rate payers and no market power.

Virtually all of LG&E's shared service employees (many of whom have access to transmission information) occupied the same building as LG&E's two primary Marketing and Energy Affiliates, *i.e.*, LG&E's WMF, and LG&E's principal affiliated power marketer (LEM). When we pointed out to LG&E that shared service employees with access to transmission information and the Marketing and Energy affiliate employees share facilities which trigger a posting requirement, LG&E agreed to revise its posting to ensure that it is consistent with 18 C.F.R. § 358.4(b)(2) (2005).

Recommendation

We recommend that LG&E:

26. Revise its shared facilities posting to include all facilities that LG&E's Marketing and Energy Affiliates share with service employees who have access to non-public transmission information.

Actions Already Taken by LG&E

After discussions with us, LG&E revised its posting with respect to shared facilities on December 13, 2005. We reviewed the revised posting in January 2006 and found that the revised posting is not consistent with the Commission's requirements. Specifically, LG&E has not identified the facilities its Marketing and Energy Affiliates share with other LG&E functions that have access to non-public transmission information.

V. MARKET-BASED RATE TARIFF FINDING AND RECOMMENDATIONS

9. Electric Quarterly Report Inaccuracies

LG&E's Electric Quarterly Report (EQR) filing for the first quarter of 2005 contained inaccurate information for its market-based rate sales. LG&E inaccurately reported several sales transactions from its WMF to its affiliated power marketer (LEM) and reported invalid Data Universal Numbering System (DUNS) numbers for several other customers.

Pertinent Guidance

Order No. 2001 [38] provided field names for the specified information required to be filed for the EQR: transaction begin date and transaction end date fields are provided for reporting the date and hour the transaction began and ended, increment peaking name field for reporting full period (FP), Peak (P), and Off-peak (OP), and class name field for reporting non-firm (NF) and firm (FP) power sales. Order No. 2001 also required the reporting of DUNS numbers for all customers in the EQR, making the power sale and the transmission reporting requirements consistent and reducing possible confusion among similarly named, but different, providers of service.

Discussion

We reviewed a sample of LG&E's EQR filing specifically for the first quarter of 2005. We found that LG&E inaccurately reported sales transactions to LEM and reported invalid Data Universal Numbering System (DUNS) numbers for several other customers.

LG&E reported two "around the clock" sales to LEM on February 24, 2005 (transaction_unique_identifier 2005003000) and February 25, 2005 (transaction_unique_identifier 2005003080). LG&E sold 52 megawatts to LEM in each hour in Transaction 2005003000 for $47.00 during the peak period and $31.00 during the off-peak period. LG&E sold 104 megawatts to LEM in each hour in Transaction

[38] *Revised Public Utility Filing Requirements*, Order No. 2001, FERC Stats. & Regs., Regulations Preambles, ¶ 31,127 (2002), *order on reh'g,* Order No. 2001-A, 100 FERC ¶ 61,074 (2002), *order on reconsideration and clarification*, Order No. 2001-B, 100 FERC ¶ 61,342 (2002); Order No. 2001-C, 101 FERC ¶ 61,314 (2002); Order No. 2001-D, 102 FERC ¶ 61,334 (2003); Order No. 2001-E, 105 FERC ¶ 61,352 (2003); Order No. 2001-F, 106 FERC ¶ 61,060 (2004).

2005003080 for $51.50 during the peak period and $31.50 during the off-peak period. LG&E reported the off-peak period of both transactions as beginning at 12:00 AM and ending at 11:59 PM and assigned the increment peaking name as "FP" or full period rather than "OP" or off-peak. LG&E reported the peak period of these transactions as beginning at 7:00 AM and ending at 10:59 PM and assigned the increment peaking name as "FP" or full period rather than "P" or peak.

LG&E's EQR filing included 34 unique transaction identifiers where it sold energy to LEM and reported the class name of the energy sold as "NF" or non-firm. LG&E's Code of Conduct also required these sales to LEM to be posted on an EBB where LG&E reported these same sales transactions as system firm sales. When we asked LG&E to explain the discrepancy, it explained that the EQR data showing the sales as non-firm was incorrect.

LG&E reported 10 invalid DUNS numbers in its EQR for the 1st quarter 2005 for the following customers: Barbourville Water & Electric, Bardstown Municipal Light & Water, Bardwell City Utilities, Benham Electric System, City of Madisonville, City of Paris Combines Utilities, El Paso Merchant Energy L.P., El Paso Merchant Energy, LP, Owensboro Municipal Utilities, and Rainbow Energy Marketing Corp..

Recommendations

We recommend that LG&E:

27. Strengthen its written procedures to ensure all data reported in future EQR filings are in compliance with Commission regulations and reflect the correction of the errors and inconsistencies identified in this Audit Report.

28. Implement procedures to validate all customer DUNS numbers.

29. Refile all EQR reports from inception to correct the increment peaking name and the class name of power it sold to LEM.

30. LG&E shall submit all procedures to OE for approval within 30 days of issuance of a Final Audit Report in this docket.

Actions Already Taken by LG&E

LG&E advised us that it would be making corrections to its EQR filings, and that such corrections were made on January 31, 2006. We expect that the revised written procedures on EQR filings will be addressed by LG&E in its implementation plan in response to this Audit Report.

VI. IMPLEMENTATION PLAN

We recommended that LG&E submit an implementation plan to the audit staff for our approval detailing LG&E's plans to comply fully with the findings and recommendations in this Audit Report. The implementation plan should describe the actions LG&E has already taken, and will take, that are consistent with and complementary to any future structural and organizational changes that LG&E may undertake.

The implementation plan should be submitted within 30 days of issuance of a Final Audit Report in this docket. In addition, LG&E shall make quarterly filings updating the audit staff of its progress on implementing the plan. The filings shall be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

Appendix

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Michael S. Beer

June 29, 2006

Mr. Bryan Craig, Director
Division of Audits
Office of Enforcement
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

RE: *Louisville Gas and Electric Company, Kentucky Utilities Company*
Docket No. PA05-9-000

Dear Mr. Craig:

This letter sets forth the response of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies") to the draft audit report issued by the Federal Energy Regulatory Commission's ("FERC" or the "Commission"), Office of Enforcement, Division of Audits ("FERC Audit Staff") on June 14, 2006, in the above referenced docket ("Draft Audit Report"). As requested, this response addresses: (1) whether the Companies agree or disagree with each finding and recommendation set forth in the Draft Audit Report; and (2) the corrective actions planned, or taken, and target completion dates.

I. INTRODUCTION.

The Companies agree with the findings and recommendations set forth in the Draft Audit Report. Further, the Companies appreciate the opportunity to respond to the Draft Audit Report. Encouraging, facilitating, and maintaining on-going compliance with Commission's regulatory initiatives and requirements is of the highest priority to the Companies and consistent with the core values and behaviors of E.ON U.S. LLC and its parent, E.ON AG. The operational audit of the Companies' compliance with the Standards of Conduct, the Companies' Market-Based Rate Tariffs, Market-Based Rate Tariff Code of Conduct ("LG&E Code of Conduct"), and the Open Access Transmission Tariff of the Midwest Independent Transmission System Operator, Inc. (collectively, "Audit Items") has been beneficial for the Companies as the audit process revealed several areas in which the Companies could improve their existing processes and methods.

During the course of the audit, and as discussed here, the Companies have taken and will continue to take substantial steps to improve their compliance. The Companies are committed to implementing and maintaining a comprehensive internal FERC compliance program as suggested in the recent *Policy Statement on Enforcement.*[1] One of the core behaviors that defines the global E.ON corporate family is the "drive for excellence." In this regard, the Companies are committed to driving for excellence in the area of FERC regulatory compliance by implementing, monitoring, and periodically evaluating the effectiveness and efficiency of existing measures designed to ensure for full compliance.

In this regard and to clearly demonstrate the Companies' commitment to compliance, the Chairman, President, and Chief Executive Officer of the Companies has expanded the responsibilities of the Standards of Conduct Chief Compliance Officer ("CCO") to include the LG&E Code of Conduct and the Market-Based Rate Tariffs under which the Companies and any affiliates may be operating. The CCO has been further directed to prepare and implement a detailed, comprehensive compliance program that encompasses the full range of FERC regulatory obligations, and to develop and implement a strategy for enhanced training, monitoring, and auditing the effectiveness of the overall internal FERC compliance process. The Companies' ongoing commitment to compliance has the full support of the entire senior management team of E.ON U.S. LLC, as well as their commitment to support the development and the implementation of the broader FERC compliance program.

As noted in the *Policy Statement on Enforcement*, a thorough commitment to compliance must be ingrained in corporate culture. Such a commitment is established at the senior most levels of any organization and must flow down from management to front-office employees engaged in day-to-day operations. As noted above, E.ON U.S. LLC senior management is strongly committed to ensuring compliance with all applicable FERC regulatory obligations. The Companies believe that the establishment of a detailed and comprehensive internal FERC compliance program will demonstrate this commitment throughout the E.ON U.S. LLC corporate family and also to the Commission. Simply put, compliance with the letter and spirit of applicable FERC regulatory obligations is encouraged, expected, and required at all levels of our organization. Therefore, as the audit process concludes, E.ON U.S. LLC reiterates our commitment to strengthening and maintaining an effective and open culture of compliance. This commitment is an integral part of our corporate identity and reflects our core values and behaviors.

[1] *Enforcement of Statues, Orders, Rules and Regulations,* 113 FERC ¶ 61,068 (2005) ("*Policy Statement on Enforcement*").

II. RESPONSE TO PROPOSED FINDINGS AND RECOMMENDATIONS.

The Companies sincerely appreciate FERC Audit Staff's willingness to work with our employees and, where possible, provide guidance to help strengthen our overall compliance with the Audit Items. Prior to addressing specific comments on the proposed findings and recommendations, the Companies would like to highlight their cooperation with FERC Audit Staff as the audit progressed. We believe that the spirit in which the revised procedures for the Before-the-Purchase System were developed, as well as the guidance regarding Standards of Conduct training and for strengthening compliance with the Code of Conduct Electronic Bulletin Board ("EBB") posting requirements, are positive examples of how the operational audit process can work. The Companies look forward to working with FERC Audit Staff to finalize and implement post operational audit compliance plans in accordance with the process described in the Draft Audit Report.

As noted in Section I, above, the Companies agree with the findings and recommendations set forth in the Draft Audit Report. As discussed in Section I, above, the Companies and their parent, E.ON U.S. LLC, are committed to ensuring on-going compliance with the Audit Items, as well as other applicable FERC regulatory initiatives and requirements. The Companies were frankly unsettled by the number of non-compliance findings identified by FERC Audit Staff. We trust that our willingness to act without delay to address the identified non-compliance issues and take the necessary steps to strengthen and broaden their overall compliance program is, in fact, evidence of the priority the Companies give to compliance. These priorities will not change following the conclusion of the audit. Finally, the Companies would like to emphasize the importance of the absence of findings of intent to violate applicable rules or tariffs regarding the identified areas of non-compliance.

III. UPDATE OF CORRECTIVE ACTIONS TAKEN OR PLANNED AND TARGET COMPLETION DATES.

The Companies agree to submit an implementation plan within 30 days of the issuance of the final audit report. The implementation plan will set forth the distinct steps that the Companies have taken, and will take, to fully comply with the findings and recommendations set forth in the final audit report. In the interim, the Companies provide the following status report on the steps that they have taken during the course of the audit to comply with the findings and recommendations of FERC Audit Staff.

A. CODE OF CONDUCT FINDINGS AND RECOMMENDATIONS.

1. Functional, Physical, and Operational Separation of LG&E's Wholesale Merchant Function and Affiliated Power Marketer.

The Draft Audit Report directs the Companies to take all appropriate actions necessary to ensure that wholesale merchant function employees ("WMF") are functionally, physically, and operationally separated to the maximum extent practical, as required under the LG&E Code of Conduct, from their affiliated power marketer, LG&E Energy Marketing Inc. ("LEM"). Draft Audit Report at 8-11. As discussed below, the Companies have already implemented, or propose to implement, corrective measures designed to satisfy these requirements. While the final details of the steps taken by the Companies to achieve the appropriate degree of functional, physical and operational separation required by the LG&E Code of Conduct will be set forth in their implementation plan, the Companies provide the following update.

a. Functional Separation Concerns.

The Draft Audit Report states that the functional separation between WMF and LEM is not consistent with the LG&E Code of Conduct. Draft Audit Report at 8-9. The Draft Audit Report cites two examples of the lack of appropriate functional separation between WMF and LEM. *Id.* at 8-9. The first example concerns meetings jointly attended by WMF and LEM personnel and the Senior Vice President, Energy Marketing ("SVP Energy Marketing") at which certain market information about WMF and LEM trading operations was discussed. *Id.* The second example addresses certain aspects of the job description for the SVP Energy Marketing's indicating "that the SVP Energy Marketing is expected to coordinate WMF and LEM activities to provide a greater return for the LG&E corporate family." *Id.* at 9. The Companies agree with the findings made in the Draft Audit Report regarding the functional separation between WMF and LEM and agree to implement post-audit corrective measures to improve their compliance with the LG&E Code of Conduct functional separation requirements.

In order to ensure clear and full compliance with the functional separation requirements of the LG&E Code of Conduct, the Companies propose to implement the following corrective measures. First, the Companies propose to revise the job description of the SVP Energy Marketing. All language in the current job description indicating that SVP Energy Marketing is expected to "coordinate WMF and LEM activities to provide a greater return for the LG&E corporate family" will be deleted. As revised, the job description will require the SVP Energy Marketing to exercise his corporate oversight and management responsibilities for WMF and LEM in a manner that ensures that WMF and LEM: (1) are treated as separate and distinct businesses in accordance with the functional separation requirements of the LG&E Code of Conduct; and (2) will produce the greatest return for the E.ON U.S. corporate family on an independent and stand-alone basis. Further, the revised job description will acknowledge the SVP Energy Marketing's obligation to comply with the No Conduit Rule set forth in the LG&E Code of Conduct.

Second, as discussed in Section III.A.1.b, below, the SVP Energy Marketing has discontinued holding monthly trading meetings that are jointly attended by WMF and LEM staff. Concurrent with the physical relocation of LEM to an enclosed work space on the Fourth (4^{th}) Floor West section of the E.ON U.S. LLC Building located at 220 W. Main Street in Louisville, Kentucky ("E.ON Center"), the SVP Energy Marketing has implemented a process change and now meets with WMF and LEM separately on a monthly basis to discuss relevant business issues. Further, as noted in Section III.A.2.a, below, the Companies have implemented a process change that requires the CCO or his designee to attend any business meetings where both WMF and LEM staff are present. This process change squarely covers any meeting where the SVP Energy Marketing also may be present with both WMF and LEM staff.

Third, per prior discussions with FERC Audit Staff on or about February 6, 2006, the Companies commit to adhere to the chain of command for WMF and LEM in order to maintain separation between the SVP Energy Marketing and the execution of day-to-day WMF and LEM activities consistent with the SVP Energy Marketing's status as one of most senior executives in the E.ON U.S. LLC corporate family and the Companies' existing delegations of corporate authorities.

Together with the corrective measures designed to ensure proper physical and operational separation discussed in Sections III.A.1.b and c, below, the Companies respectfully submit that, given the relatively small size of E.ON U.S. LLC regulated and unregulated trading operations, these corrective measures will provide the functional separation required by the LG&E Code of Conduct (from both a substantive and optical perspective). The Companies will submit the specific measures for ensuring full compliance with the LG&E Code of Conduct functional separation requirements as part of their post-audit implementation plan.

b. Physical Separation Concerns.

The Draft Audit Report states that the physical separation between WMF and LEM is not consistent with the LG&E Code of Conduct. Draft Audit Report at 9. The Companies agree with the findings regarding physical separation concerns and, as discussed below, have implemented a number of corrective measures that assure that the physical separation of WMF and LEM is consistent with the LG&E Code of Conduct.

As a follow-up to the discussion regarding the physical proximity of WMF and LEM in their letter to FERC Audit Staff dated January 11, 2006 ("January 11 Letter"), the Companies hereby confirm that as of March 31, 2006, LEM has been physically relocated to an enclosed work space on the 4th Floor West section of E.ON Center. The enclosed LEM work space on the 4th Floor West section of the E.ON Center is secured by a card-key reader that only permits access to LEM personnel and a limited group of support personnel that may be shared consistent with requirements of the LG&E Code of Conduct, such as the CCO and designees, internal legal counsel, Energy Marketing Accounting, Trading Controls, and Operations Analysis/System Implementation.

Neither the 4th Floor of the E.ON Center nor the enclosed LEM workspace located thereon can be accessed by WMF personnel. Conversely, neither the 7th Floor of the E.ON Center nor the enclosed WMF workspace located thereon can be accessed by LEM personnel.

A full description of the specifics regarding the key card access restrictions to the enclosed LEM work space on the 4th Floor West section, and to the WMF work space on the 7th Floor North section, of the E.ON Center will be provided in the Companies' post-audit implementation plan. Further, written procedures governing the access to the WMF and LEM workspaces for authorized E.ON U.S. LLC employees and other permitted persons will be adopted by the Companies as part of comprehensive Code of Conduct compliance program.

c. Operational Separation Concerns with Respect to Recorded Phone Calls.

The Draft Audit Report states that the operational separation between WMF and LEM with respect to recorded phone calls on two (2) RACAL digital tape recorders is not consistent with the LG&E Code of Conduct. Draft Audit Report at 9-10. The Companies agree with these findings as set forth in the Draft Audit Report and have already undertaken measures to ensure compliance with the operational separation requirements of the LG&E Code of Conduct as it relates to recorded phone conversations. Further, as discussed below, the Companies propose to implement additional measures to ensure compliance with this aspect of the operational separation requirement.

In their January 11 Letter, the Companies proposed to implement certain internal controls to ensure appropriate operational separation under the LG&E Code of Conduct with respect to WMF and LEM trader telephone conversations using RACAL digital tape recorders. January 11 Letter at 5. The Companies continue to pursue the implementation of the corrective measures outlined in the January 11 Letter. However, the Companies hereby inform FERC Audit Staff that, on or about December 14, 2005, the RACAL digital tape recorders were replaced by two (2) NiceCall Focus III voice recording systems that contain technology that permit the "desktop review" of previously recorded conversations. One NiceCall Focus III machine is dedicated exclusively for use by LEM. The second machine is dedicated for use exclusively by WMF. The Companies believe that their investment in separate voice recording machines for LEM and WMF that contain "desktop review" technology is a substantial step towards achieving the operational separation required by the LG&E Code of Conduct with respect to recorded calls.

Distinct from the RACAL recorders, the NiceCall Focus III voice recording systems are operated on a stand-alone basis and are not interconnected in any way, physically or operationally. As noted above, these machines contain technology that allows traders to engage in desktop review of prior recorded calls. As discussed in greater detail in the Companies' post-audit implementation plan, traders for WMF and LEM are assigned specific channels on the NiceCall Focus III machine assigned to their business unit and are only permitted access to those channels.[4] In order to provide appropriate risk management and corporate oversight of trading activities, supervisory personnel within LEM and WMF are also permitted to access the recorded conversations of traders assigned to their business unit.[5] Limited access to recorded conversations is permitted by certain "shared support" personnel that are subject to the No Conduit Rule under the LG&E Code of Conduct, such as internal legal counsel, Trading Controls, Energy Accounting, Contract Administration, and the CCO and his designees.

In two distinct respects, the Companies believe that the use of the separate NiceCall Focus III machines with "desktop review" technology will help ensure on-going compliance with the operational separation requirements of the LG&E Code of Conduct. First, "desktop review" technology eliminates the need for WMF and LEM personnel to have physical access to the work space where these machines are currently stored. Second, because different NiceCall Focus III machines are used by WMF and LEM, taken together with the fact that WMF and LEM have been physically separated as described in Section III.A.1.b, above, there is no risk of personnel from one operation gaining indirect, remote access to non-public market information on the other operation's recorded lines.

As discussed in greater detail in their post audit implementation plan, the Companies propose to adopt a comprehensive set of written procedures designed to facilitate on-going compliance with LG&E Code of Conduct operational separation requirements as applied to recorded calls for both the new NiceCall Focus III machines and for historic conversations recorded on the RACAL tapes. The Companies will adopt these written procedures as part of comprehensive Code of Conduct compliance

[4] Because separate NiceCall Focus III machines are used by LEM and WMF, traders for LEM may only access assigned channels on the NiceCall Focus III machine that is dedicated for use exclusively by LEM. Similarly, WMF traders may only access assigned channels on the NiceCall Focus III that is dedicated for use exclusively by WMF.

[5] LEM supervisory personnel may only access voice recordings on the NiceCall Focus III machine dedicated for use exclusively by LEM. Similarly, WMF supervisory personnel may only access voice recordings on the NiceCall Focus III machine dedicated exclusively for use by WMF.

program. With regard to historic conversations recorded on the RACAL tapes, the Companies propose to implement internal controls consistent with those outlined in their January 11 Letter.

In that regard, the January 11 Letter proposed to implement a policy or set of procedures designed to ensure that: (1) trading personnel of one operation (whether WMF or LEM) will not have access to RACAL tapes of recorded conversations of the other; and (2) that anyone requesting access to RACAL tapes of recorded conversations must listen to such tapes in a location that does not permit access to phone conversations of the other group (*i.e.*, in their assigned work spaces). Specifically, the Companies proposed to develop a log book or another form of written record to document requests for access to historic conversations recorded on the RACAL tapes that requires the following information:

- The name of the person(s) seeking access to the RACAL tapes containing the recorded phone conversations;

- The name of their business unit (*e.g.*, WMF, LEM, legal or regulatory);

- A brief description of the recorded conversations on the RACAL tapes for which access to the tapes is sought;

- A brief description of the reasons for reviewing the recorded conversations on the RACAL tapes (*e.g.*, contract dispute, incorrect trade confirmation.

Finally, the Companies propose to include written procedures to provide for the periodic review by the CCO or his designee of the RACAL tape log book or other written record. These written procedures will be adopted as part of a comprehensive Code of Conduct compliance program

2. Sharing of Market Information.

a. Joint Staff Meetings Between WMF and LEM.

The Draft Audit Report states that the WMF shared marketing information through presentations at joint staff meetings in violation of the LG&E Code of Conduct. Draft Audit Report at 12-13. The Companies agree with these findings regarding joint staff meetings between WMF and LEM as set forth in the Draft Audit Report. As discussed below, the Companies have already undertaken significant measures to ensure compliance with the information sharing restrictions in the LG&E Code of Conduct and propose to formalize these measures in their post-audit implementation plan.

In June 2005, the Companies revised the agenda of the monthly trading meetings jointly attended by WMF and LEM personnel, as well as the SVP Energy Marketing and staff from Market Analysis, Trading Controls, Operations Analysis, and Fuels Management to address concerns raised by FERC Audit Staff regarding the sharing of WMF historical off-system sales ("OSS") summary information during these meetings. *See* Draft Audit Report at 14. From the period June 2005 through March 31, 2006, the Companies altered the agenda so that the presentation regarding WMF's OSS was not made until LEM employees were dismissed from the meeting. Since December 2005, the Companies have adopted certain process changes, including the requirement to have the CCO or his designee attend all business meetings jointly attended by WMF and LEM personnel. The CCO or his designee maintains a high-level agenda and/or minutes of such joint meetings.

Please note that beginning on or about April 1, 2006, the SVP Energy Marketing discontinued scheduling and holding monthly trading meetings that are jointly attended by WMF and LEM staff. The monthly trading meetings are now held by the SVP Energy Marketing with WMF and LEM staff separately. These separate meetings are also attended by staff from Market Analysis, Trading Controls, Operations Analysis, and Fuels Management, who are shared support staff under the LG&E Code of Conduct and subject to the No Conduit Rule. In accordance with the No Conduit Rule, non-public WMF or LEM market information discussed during meeting with one business unit (*i.e.*, WMF) is not shared in meetings with the other business unit (*i.e.*, LEM) and vice versa.

As discussed in greater detail in their post-audit implementation plan, the Companies propose to adopt the process changes as part of a comprehensive Code of Conduct compliance program. In addition, the Companies propose to memorialize as part of a comprehensive Code of Conduct compliance program that monthly trading meetings discussed in the Draft Audit Report are held separately with WMF and LEM staff.

b. Password Access to EMS Information.

The Draft Audit Report states that Companies password access controls to the shared Energy Management System ("EMS") were insufficient and inconsistent with the Companies' password security policy. Draft Audit Report at 13. Prior to February 2004, the Companies permitted WMF and LEM users to access the EMS using separate group accounts and passwords, rather than using unique user accounts and passwords. *Id.* As a consequence, the Draft Audit Report states that failure to require unique password access was contrary to the Companies' password security policy and increased the risk of inappropriate information access via the EMS. *Id.* The Companies agree with the findings regarding password access to EMS information as set forth in the Draft Audit Report and have already taken corrective measures to address these concerns.

As noted in the Draft Audit Report, in February 2004, the Companies have implemented individual user-ids and passwords for its current GE/Harris EMS. As required by GE/Harris vendor support requirements, a common user-id still exists solely and exclusively for maintenance purposes. However, the WMF and LEM EMS users do not have access to the vendor required common user-id and may only access the EMS through their own unique user-id and password.

The Companies are in the process of installing a new Open Systems International ("OSI") EMS. It is anticipated that the OSI EMS will become fully operational on or about December 31, 2006. As part of their post-audit operational plan, the Companies will provide an update on the status of the installation of the new OSI EMS and on a quarterly basis thereafter until the OSI EMS becomes fully operational. In addition, the Companies agree to conduct an independent review by their internal audit department or an outside audit firm when the OSI EMS is implemented to ensure that there is no unauthorized EMS screen access by WMF and LEM staff. Finally, a requirement mandating the periodic review of EMS access requirements will be adopted as part of the Companies' existing Standards of Conduct compliance program and the proposed comprehensive Code of Conduct compliance program.

3. Posting Information on Sales to Affiliates at Market-Based Rates.

a. Accessibility of EBB Information to Market Participants.

The Draft Audit Report raised a number of concerns regarding the accessibility of the Companies EBB to market participants. Draft Audit Report at 15-16. The Companies agree with the findings regarding the accessibility of EBB information to market participants.

As noted in the Companies' January 11 Letter, as of January 2006, a link to the EBB, entitled "LEM Transactions" was posted on the left-hand column of regulatory page of the E.ON U.S. LLC Internet site. January 11 Letter at 6 n.2. The regulatory page of the E.ON U.S. LLC Internet site can be accessed at the following web address: http://www.eon-us.com/regulatory.asp. Subsequently, to ensure the easiest possible ratepayer and market participant access to the EBB, the Companies posted an additional EBB link, entitled "LEM Transactions EBB," on the lower right-hand corner of the homepage of E.ON U.S. LLC Internet site. The homepage of the E.ON U.S. LLC Internet site can be accessed at the following web address: http://www.eon-us.com/home.asp. Accordingly, as of the date hereof, there are two (2) separate and easily accessible links on the E.ON U.S. LLC Internet site for interested parties to view the EBB.

A copy of the regulatory page and the home page of the E.ON U.S. LLC Internet site containing the existing links to the Companies' EBB on are appended hereto as Attachment A.

b. Posted Offers to Sell on the EBB.

The Draft Audit Report states that Companies' efforts to post offers to sell to LEM on the EBB were not consistent with posting requirements set forth in Paragraphs 7 and 8 of the LG&E Code of Conduct. Draft Audit Report at 16-17. The Companies agree with the findings regarding posted offers to sell on the EBB as set forth in the Draft Audit Report. As noted in their January 11 Letter, the Companies proposed to develop process changes to facilitate significantly stronger compliance with the posting requirements set forth Paragraphs 7 and 9[1] of the LG&E Code of Conduct.

A presentation generally outlining the proposed process changes was made and submitted to FERC Audit Staff on December 16, 2005. The process changes proposed in the presentation and described below are based on the Companies' understanding of existing Commission precedent addressing the need for implementing the EBB requirement when regulated utilities engage in market-based sales with unregulated affiliates. Specifically, Commission precedent is clear that when traditional public utilities engage in power sales to an affiliated power marketer, public utilities may have an incentive to favor their affiliated marketer to the detriment of captive ratepayers.[6] Such behavior can take place when a public utility and its affiliated power marketer transact in ways that result in a

[6] The paragraphs in the currently effective LG&E Code of Conduct originally accepted for filing by the Commission in Docket No. ER99-1623 were incorrectly numbered. There are a total of nine (9) paragraphs. The eighth and ninth paragraph of the LG&E Code of Conduct are incorrectly labeled paragraphs 9 and 10.

[7] *See Detroit Edison Co., et al.*, 80 FERC ¶ 61,348 at 62,198 (1997); *see also Aquila, Inc.*, 101 FERC ¶ 61,331 at P 8 (2002); *FirstEnergy Corp. et al.*, 94 FERC ¶ 61,182 at 61,630 (2001); *Alliant Services Co.*, 85 FERC ¶ 61,344 at 62,335 (1998).

diversion of benefits from the public utility (and its captive ratepayers) to the affiliated power marketer (and its shareholders).[7]

To avoid the diversion of benefits from captive ratepayers to shareholders, the Commission requires that utilities engaging in power sales to affiliated marketers must price such transactions at a rate no lower than the rate the utilities charge to non-affiliates.[8] The requirement to "simultaneously" post offers to, and executed sales with, an affiliate marketer on an EBB is intended to provide transparency to this affiliate sales process. The purpose for providing such transparency is to allow interested third-parties (*i.e.*, ratepayers and market participants), as well as the Commission itself, to independently verify whether such affiliate transactions were priced in accordance with this standard.

As a practical business and operational matter, it is extremely difficult, if at all possible, to comply with the literal language set forth in Paragraphs 7 and 9 of the LG&E Code of Conduct, *i.e.*, mandating the simultaneous posting of: (1) offers to LEM; and (2) executed affiliate power sales transactions. Due to the pace of modern trading operations, transactions are negotiated and executed within minutes. Traders in the WMF cannot in such a short period of time: (1) survey the market and develop a credible picture of the prevailing market price for a given product; (2) negotiate with several counterparties to obtain the best sales price possible; (3) execute trades; and (4) post offers to, and executed sales with, LEM at the same time they take place.

The proposed EBB posting process changes discussed with FERC Audit Staff are intended to reflect the practical realities of engaging in real-time trading activities within a small organization. More importantly, the Companies believe that the process changes discussed with FERC Audit Staff are consistent with both the intent and spirit of the Commission's existing precedent and policies designed to prevent affiliate abuse and self-dealing described above.

The Companies believe that addressing these operational realities in a practical manner must have been considered by the Commission when it established the simultaneous posting requirements codified in Paragraphs 7 and 9 of the LG&E Code of Conduct. Further, the Companies believe that these operational realties must have been intended when Paragraphs 7 and 9 were written. As proposed to FERC Audit Staff, the EBB posting process changes will provide ratepayers, market participants, and the Commission with a workable, easily accessible, and transparent mechanism for monitoring on a real-time basis whether sales by the Companies to LEM may result in an improper diversion of benefits from ratepayers due to the failure to price such transactions in a manner that complies with the LG&E Code of Conduct.

The Companies recognize the complexities of this particular issue and look forward to working with FERC Audit Staff to finalize these process changes as part of their post-audit implementation plan. The final process changes for posting offers to sell on the EBB will be adopted as part of a comprehensive Code of Conduct compliance program. As discussed in greater detail in the Companies' post-audit implementation plan, E.ON U.S. LLC senior management will supervise the formal roll-out sessions for implementing the final EBB posting process changes. Specifically, the roll out and subsequent training sessions will not only discuss the purpose and application of the EBB posting

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[8] *Id.*

[9] *Id.*

process, they will also emphasize the importance of this process and the need to vigilantly assure compliance therewith. After the initial roll out, the Companies propose to conduct periodic internal reviews and follow-up training to ensure on-going compliance.

c. Prices of Affiliate Sales.

The Draft Audit Report states that the Companies did not have any written procedures or other controls for WMF traders to determining whether sales to LEM were consistent with the affiliate pricing provisions set forth in Paragraph 6 of the LG&E Code of Conduct. Draft Audit Report at 17. The Draft Audit Report notes that the WMF traders established the market price for next-hour energy sales to LEM through telephone queries with potential counterparties and through broker quotes. *Id.* The Draft Audit Report further states that, although no evidence that WMF traders transacted with LEM at less than market price, WMF traders did not generally employ strong controls to establish the market prices. *Id.* The Companies agree with the findings relating to the pricing of affiliate sales as set forth in the Draft Audit Report.

The process changes for posting offers to sell on the EBB discussed in Section III.A.3.b, above, were addressed in the presentation presented to FERC Audit Staff on December 16, 2005. In relevant part, the process changes outline the steps by which WMF traders must determine whether posted offers to sell to LEM hourly or daily energy are priced no lower than prevailing market prices for each product. These procedures provide for a specific period after an offer to sell to LEM is posted on the EBB during which WMF traders must exercise commercially reasonable efforts (*i.e.*, due diligence) to survey the market and determine whether non-affiliates have any interest in pursuing an opportunity equivalent to that being offered to LEM. The WMF traders may not transact with LEM until after the specified posting period has expired. If, at the expiration of such period, an offer to sell to LEM posted on the EBB is the best and highest price available (*i.e.*, no lower than the price offered or sold to non-affiliates), the Companies may execute the sale to LEM.

As discussed in greater detail in the Companies' post-audit implementation plan, these procedures will be adopted as part of a comprehensive Code of Conduct compliance program.

d. EBB Postings in 2001.

The Draft Audit Report identifies certain concerns that took place in 2001 relating to whether, for a period of time, the EBB was properly used to post offers and sales from WMF to LEM to support a long-term sales obligation that LEM had with Morgan Stanley. Draft Audit Report at 17. The Companies agree with the findings regarding the EBB postings in 2001 as set forth in the Draft Audit Report. E.ON U.S. LLC senior management is deeply committed to ensuring that the Companies use the EBB to properly post offers and sales to LEM in accordance with the LG&E Code of Conduct requirements.

E.ON U.S. LLC has and will continue to commit the time and resources necessary to internal compliance measures designed to facilitate an enhanced understanding of, and compliance with, the EBB posting requirements set forth in the LG&E Code of Conduct. As discussed with FERC Staff at length and proposed in the Companies' December 16, 2005 presentation, E.ON U.S. LLC management believes that significantly enhanced compliance with the EBB posting requirements may be achieved through:

- Implementing a revised user friendly EBB offer matrix that contains key deal parameters and clearly articulates appropriate definitions and user guidelines;

- Providing formal employee training regarding the purpose, application and importance of the EBB posting process (including potential ramifications for non-compliance -- both internally and externally);

- Implementing additional internal controls designed to ensure that, when offers to LEM are made and sales are executed, all required EBB postings are timely made and consistent with the LG&E Code of Conduct; and

- Providing periodic follow-up training and reviewing the revised EBB posting process periodically to ensure that it is operating correctly.

As will be discussed in greater detail in the Companies post-audit implementation plan, because a true culture of compliance flows down from the top of corporate organizations, the Companies propose that the process changes for the EBB posting process will be formally rolled out by current E.ON U.S. LLC management. Senior management will ensure proper oversight of employee training sessions regarding the scope, application and importance of the EBB posting process. In addition, management will ensure that appropriate resources are dedicated to conduct periodic internal reviews and follow-up training to ensure on-going compliance with the EBB posting requirements.

B. STANDARDS OF CONDUCT FINDINGS AND RECOMMENDATIONS.

As discussed in Section I above, as part of their post-audit implementation plan, the Companies propose to undertake a comprehensive review of their Standards of Conduct Written Procedures ("SCWP") posted on the E.ON U.S. LLC Internet site, and revise and update the SCWP as necessary. The comments below respond to the specific findings and recommendations set forth in the Draft Audit Report.

1. <u>Disclosure of Transmission and Customer Information</u>.

a. <u>Disclosure of Transmission Information by Telephone</u>.

The Draft Audit Report identifies three instances where transmission function employees of the Companies disclosed non-public transmission information to regulated generation dispatchers during the course of reliability-related Transmission Line Loading Relief/generation redispatch events ("Generation Redispatch Events"). Draft Audit Report at 20-21. Because the Companies regulated generation dispatchers are organizationally and functionally housed in the WMF business unit (an Energy Affiliate), the identified transmission information was disclosed through non-public communications. *Id.* at 17. The Companies agree with the factual findings regarding the disclosure of transmission information by telephone as set forth in the Draft Audit Report, subject to the following factual clarification. The identified disclosures of transmission information occurring by telephone during Generation Dispatch Events were posted on the Standards of Conduct Page of the E.ON U.S. LLC Internet site on January 13, 2006. The posting can be found at: <u>http://www.eon-us.com/regulatory/disclosure_of_information.pdf</u>.

In their January 11 Letter, the Companies proposed to develop certain process changes to ensure that any information disclosed by transmission function employees or by a third-party Transmission Provider are promptly reported to the CCO for evaluation and, where necessary, posted on the OASIS or the E.ON U.S. LLC Internet site. January 11 Letter at 8-9. In the intervening period, the process changes outlined below have been implemented by the Companies. These process changes govern the behavior of both transmission function employees and regulated generation dispatchers during Generation Redispatch Events and include the following concepts:

- During Generation Redispatch Events, transmission function employees are only to provide specific redispatch instructions.

- Absent emergency circumstances affecting system reliability, transmission function employees may not provide regulated generation dispatchers with information regarding the cause of the Generation Redispatch Event.

- Transmission function employees and regulated generation dispatchers are required to document and provide prompt notice to the CCO or his designee of any instance in which non-public transmission information is disclosed to regulated generation dispatchers, whether by transmission function employees or any other third party (including, but not limited to, a security coordinator or reliability authority, or another Transmission Provider).

- In the event of any disclosures of non-public transmission information by a third-party (including, but not limited to, a security coordinator or reliability authority, or another Transmission Provider), apart from notifying the CCO, transmission function employees and regulated generation dispatchers will comply with the No Conduit Rule.

- Regulated generation dispatchers should <u>not</u> trade on any non-public transmission information improperly disclosed to them.

As will be described in greater detail in the Companies' post-audit compliance plans, the process changes outlined above will be converted into written procedures and incorporated into the Companies' existing SCWPs and future Standards of Conduct training programs sponsored by the Companies.

b. <u>Disclosure of Transmission Information at a Meeting Attended by Transmission and Marketing Employees</u>.

The Draft Audit Report identifies one meeting in which transmission personnel and marketing personnel were present at which the Companies' transmission personnel disclosed non-pubic information regarding the status of two transmission projects. Draft Audit Report at 21. The Draft Audit Report notes that the disclosure was not posted on the OASIS in a timely manner. *Id.* As noted in the Draft Audit Report, no evidence was found that Companies' Energy or Marketing Affiliates traded on this information. *Id.* The Companies agree with the findings regarding the disclosure of transmission information at a meeting attended by transmission and marketing employees as set forth in the Draft Audit Report.

The Companies posted the non-public transmission information disclosed in the meeting identified in the Draft Audit Report on the E.ON U.S. LLC Internet site at: http://www.eon-us.com/regulatory/disclosure_of_information.pdf on March 31, 2006. Further, beginning in April 2005, the Companies adopted certain process changes in response to concerns raised by FERC Audit Staff that cross-functional business meetings between transmission function employees and employees of Energy or Marketing Affiliates ("C/F Meetings") create the potential for the sharing of non-public transmission information. Since April 2005, the CCO or his designee has attended all identified C/F Meetings. The CCO or his designee maintains a high-level agenda and/or minutes for each meeting. The C/F Meetings include not only senior level staff meetings but also meetings attended by line level Transmission Function Employees and employees of Energy Affiliates.

In addition, the Companies propose to continue to conduct periodic "function specific" training sessions, including those with E.ON U.S. LLC senior management, to ensure that employees at all levels of the E.ON U.S. LLC organization fully understand the scope and application of the Standards of Conduct restrictions on the sharing of non-public transmission information, including the requirements to post disclosures of non-public transmission information. As discussed in greater detail in their post-audit implementation plan, the Companies propose to: (1) adopt procedures detailing the need for the CCO or his designee to be present at all C/F Meetings as described above and incorporate such procedures into its SCWPs; and (2) will provide additional information about the "function specific" training sessions.

c. Disclosure of Customer Load Data by E-Mail.

The Draft Audit Report states that a transmission function employee e-mailed a marketing employee specific, non-pubic customer load information on a monthly basis through February 2005. Draft Audit Report at 21. The Draft Audit Report notes that the Companies failed to post these disclosures on the OASIS in a timely manner. *Id.* The Companies agree with the findings regarding the disclosure of customer load data by e-mail as set forth in the Draft Audit Report.

As noted in the posted disclosure, the customer information at issue involved after-the-fact, monthly historic peak transmission load information. This information is used by the Midwest ISO to invoice the Companies for their Schedule 10 charges under the Midwest ISO's Open Access Transmission Tariff (or Module B of the Day 2 TEMT). The WMF is responsible for budgeting, approving and paying the Midwest ISO invoice. The non-public customer load data disclosed via e-mail to marketing employee identified in the Draft Audit Report was posted on the E.ON U.S. LLC Internet site on March 31, 2006 at: http://www.eon-us.com/regulatory/disclosure_of_information.pdf.

Since February 2005, the Companies have implemented process changes to ensure that transmission function employees no longer provide non-public customer load information to Energy or Marketing Affiliate employees. As will be discussed in greater detail in their post-audit compliance plan, these process changes will be memorialized and incorporated into the Companies' SCWPs. In addition, the Companies agree to perform a review of all transmission and customer information shared through e-mail distribution in order to ensure that such information is not inappropriately shared with Energy or Marketing Affiliate employees. The Companies further propose to implement new written procedures that require the periodic review of such e-mail distributions to ensure ongoing compliance with the Standards of Conduct.

2. Standards of Conduct Training.

The Draft Audit Report states that the Companies' Standards of Conduct training program was inconsistent with the Commission's regulations and the Companies' SCWP and implementation plans. Draft Audit Report at 24. During the audit, FERC Audit Staff discussed the Companies' training with the CCO, his designees and other E.ON U.S. LLC officials. Subsequently, on November 10, 2005, the Companies submitted a letter outlining an enhanced Standards of Conduct training program. *Id.* FERC Audit Staff found the proposed compliance plan to be consistent with Order No. 2004 and proposed findings and recommendations. *Id.* The Companies accept the findings regarding Standards of Conduct training as set forth in the Draft Audit Report.

The 2005 edition of the Companies' Standards of Conduct training took place from November 17, 2005 through December 31, 2005. The 2005 training program required the participation of <u>all</u> employees in the E.ON U.S. LLC corporate family at the manager level and above, as well as employees with the words or phrases "supervisor," "team leader," or "group leader" in their job title.[9] In addition, the Companies trained <u>all</u> employees in the following lines of business: (1) the Companies' Transmission Function; (2) All Energy Marketing Personnel (regulated and unregulated); (3) Information Technology; (4) Accounting and Finance; (5) Corporate Communications; (6) Legal; and (7) Regulatory. These functional areas of responsibility were selected because employees in such areas have or may have access to non-public transmission information through the Companies' financial books of account, records or contracts or real-time, day-to-day operations.

As noted in the Draft Audit Report, in 2005, the Companies significantly increased the number of employees who have received the Edison Electric Institute ("EEI")-developed, electronic Standards of Conduct training program by eighty percent (80%), from approximately 610 to approximately 1,100. The Companies are committed to further strengthening their training program to ensure that on a going-forward basis it remains consistent with Commission requirements and internal training plans. As part of this process, the Companies will memorialize new process changes for ensuring that new employees and transfers receive the appropriate Standards of Conduct training. The Companies' future Standards of Conduct training plans will be discussed in greater detail in their post-audit implementation plan.

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[10] Included within the group of employees described above are certain field personnel in the Companies' distribution function, such as managers and supervisors of substation construction crews which respond to outages that can affect the Companies integrated transmission and distribution systems. In addition, this group of employees included all managers, supervisors or above higher ranking personnel that are employed by Energy Affiliates that operate generation facilities on behalf of other investor-owned utilities

3. Controls Used to Limit Access to the System Control Centers.

a. CCO Permission to Visit the System Control Centers.

The Draft Audit Report states the Companies did not follow Section IV.A.2.b of their posted SCWP to control and track access of its marketing employees to their Waterside and Dix Dam system control centers. Draft Audit Report at 27. The Companies agree with the findings regarding CCO permission to visit the system control centers as set forth in the Draft Audit Report. Below the Companies discuss certain corrective measures that have already been undertaken to address concerns identified by FERC Audit Staff.

As noted in the Draft Audit Report, on January 10, 2005, the Companies revised the Standards of Conduct page of the E.ON U.S. LLC website to include a link titled, "Request for Access to Transmission Control Center." The link can be found at: http://www.eon-us.com/regulatory/soc_request_access.asp. The link provides instructions for the submission of written, electronic requests by employees of Energy and Marketing seeking access to the Transmission Control Centers. Consistent with Section IV.A.2.b of the Companies' SCWP, the link directs Energy or Marketing Affiliate employees to submit the following information to the CCO as part of a request for access to the to the Transmission Control Centers:

- The proposed time and date that access to the Transmission Control Centers is required; and

- A verifiable and legitimate business purpose for seeking access to such facilities.

Consistent with Section IV.A.2.b of SCWP, the link states that the CCO shall: (1) review such requests and approve or deny them; and (2) maintain electronic copies of all forms submitted and his decision to approve or deny such requests for a period of three (3) years.

Subsequently, on February 2, 2006, the Companies posted an announcement on the E.ON U.S. LLC Intranet site prominently announcing the new "Request for Access to Transmission Control Center" link on the Standards of Conduct section of Regulatory page of the E.ON U.S. LLC Internet site. The announcement of the "Request for Access to Transmission Control Center" link was made available to all E.ON U.S. LLC employees as part of the daily "News Transmission" published on the E.ON U.S. LLC Intranet site. In addition, an e-mail blast was distributed to all employees highlighting the "Request for Access to Transmission Control Center" link as a headline story in the "News Transmission" items for February 2, 2006.

As will be discussed in greater detail in their post-audit implementation plan, the Companies will further review and strengthen its system control center access procedures as directed in the Draft Audit Report. Further, the Companies commit to internally announce on a periodic basis the "Request for Access to Transmission Control Center" link on the Standards of Conduct section of Regulatory page of the E.ON U.S. LLC Internet site.

b. Controls on Visitors Entering the System Control Centers.

The Draft Audit Report states that the written log books documenting visitors' access to the Waterside and Dix Dam system control centers were inconsistent with Companies' SCWPs. Draft Audit Report at 28. Specifically, the written log books did not collect some pertinent information that was required in Section IV.A.2.b of the SCWPs. *Id.* The Companies accept the findings regarding controls on visitors entering the system control centers as set forth in the Draft Audit Report

The Companies confirm that by January 13, 2006, the log books located at the Waterside and Dix Dam system control centers were in place and updated to contain the same fields of inquiry set forth in Section IV.A.2.b of the SCWP, which include the following:

- The name of the transmission customer;
- Date and time of the visit;
- The name of the Transmission Function Employee or other Company Personnel (as that term is defined in the SCWP) hosting the transmission customer;
- Whether the transmission customer is an affiliate; and
- The purpose of the visit.

The update of the logbooks to include these fields of inquiry ensures consistency with the Companies' existing SCWP procedures and creates an audit trail that allows for independent verification regarding whether the Companies' Energy and Marketing Affiliate employees had access to system control centers in any way that differed from non-affiliate transmission customers. The Companies agree to the recommendations set forth in the Draft Audit Report and will provide greater detail regarding additional corrective measures (if any are required) in their post-audit implementation plan.

c. <u>Access to Transmission Information Once Inside the System Control Center</u>.

The Draft Audit Report raises concerns that non-transmission function employee visitors to Waterside and Dix Dam system control centers could gain access through a direct, external line of sight to certain non-public transmission information posted on monitors and boards within these facilities actual transmission system control rooms. Draft Audit Report at 29. The Companies agree with the findings regarding access to transmission information once inside the system control centers as set forth in the Draft Audit Report.

In their January 11 Letter, the Companies committed to install by January 13, 2006 certain temporary, but effective, covers on all windows on doors, or windows that serve as partitions or walls for purposes of impeding a direct view into the control rooms at Waterside and Dix Dam. The Companies hereby confirm that such temporary covers were in fact installed by January 13, 2006. Further, the Companies committed to implement a permanent solution through the use of frosted glass or another similar technique by the end of the first quarter of 2006. By this letter, the Companies hereby confirm that, prior to the end of the first quarter of 2006, permanent window frosting treatment covers were installed all windows on doors, or windows that serve as partitions or walls for purposes of impeding a direct view into the control rooms at Waterside and Dix Dam.

4. Organizational Charts.

The Draft Audit Report states that Companies have not properly posted certain organizational charts showing: (1) employee information required for all business units in the sales function; (2) the position of all Energy and Marketing Affiliates with the E.ON U.S. LLC family corporate structure; and (3) that the Companies use a service company as an employment mechanism for the Transmission Provider and for its Energy and Marketing Affiliates. Draft Audit Report at 30-32. The Companies agree with the findings regarding the posting of organizational charts as set forth in the Draft Audit Report.

On Friday, June 16, 2006, the Companies and FERC Audit Staff held a conference call for purposes of ensuring that the Companies fully satisfied the organizational chart posting requirements and concerns articulated in the Draft Audit Report. The Companies appreciate FERC Audit Staff's cooperation and help in this process. As will be discussed in greater detail in their post-audit implementation plan, the Companies will post revised organizational charts in accordance with the directives and guidance provided by FERC Audit Staff on the June 16th call.

5. Shared Facilities.

The Draft Audit Report states that the Companies did not post a list of facilities Shared by the Transmission Provider and the Companies' Energy and Marketing Affiliates. Draft Audit Report at 33. Further, the Draft Audit Report notes that virtually all of the Companies shared service Employees occupied the same building as their two primary Marketing and Energy Affiliates -- WMF and LEM. *Id.* at 34. When FERC Audit Staff pointed out that the shared services employees with access to transmission information and the Marketing and Energy Affiliate shared facilities which trigger a posting requirement, the Companies agreed to revise its posting to ensure that it is consistent with 18 C.F.R. § 358.4(b)(2) (2005). The Companies agree with the findings regarding shared facilities as set forth in the Draft Audit Report and corrected the posting.

C. MARKET-BASED RATE TARIFF FINDING AND RECOMMENDATIONS.

The Draft Audit Report states that, for the first quarter of 2005, the Companies' Electric Quarterly Reports ("EQRs") contained inaccurate information for its sales made pursuant to their joint market-based rate tariff. Draft Audit Report at 35. Specifically, the Companies inaccurately reported several sales transactions from its WMF to LEM and reported invalid Data Universal Numbering System ("DUNS") numbers for several other customers. The Companies accept the findings regarding EQRs as set forth in the Draft Audit Report.

As noted in the Draft Audit Report, on January 31, 2006, the Companies made certain corrections to its EQR filings. The Companies agree to implement the proposed recommendations set forth in the Draft Audit Letter regarding: (1) strengthening the Companies' written procedures to ensure that all data reported in future EQR filings are in compliance with Commission regulations and reflect the correction of errors and inconsistencies identified in the Draft Audit Report; (2) implementing procedures to validate all customer DUNS numbers; and (3) refiling all EQR reports from inception to correct the incremental peaking name and class name of power sold to LEM. The refiling referenced in subsection (3) above has been completed.

The proposed corrective measures designed ensure the accuracy and sufficiency of the Companies' EQR reports and ensure compliance with their joint market-based rate tariff will be submitted with the Companies' post-audit implementation plan.

IV. CONCLUSION.

On behalf of E.ON U.S. LLC, I would like to thank the FERC Audit Staff for their time, effort and commitment to ensuring that the Companies are in full compliance with the Audit Items. I would like to again affirm E.ON U.S. LLC's commitment to meeting its obligations under the Standards of Conduct, the Code of Conduct, its Market-Based Rate Tariff and all other applicable FERC imposed regulatory obligations.

Sincerely,

Michael S. Beer
Vice President, Federal Regulation and Policy and
Standards of Conduct Chief Compliance Officer
E.ON U.S. LLC

on behalf of
Louisville Gas and Electric Company &
Kentucky Utilities Company

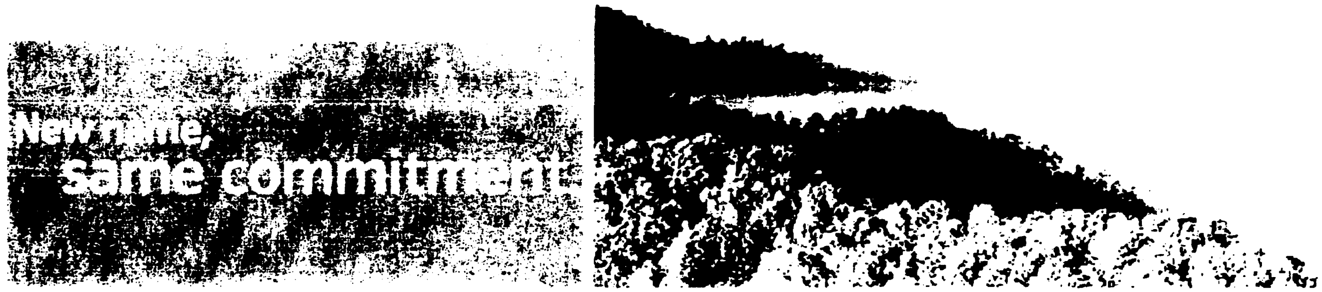
cc: Carl Coscia
Lyle Hanagami
Eliot Wessler
FERC, Office of Enforcement, Division of Audits

Steven D. Phillips
E.ON U.S. LLC

R. Michael Sweeney, Jr.
Hunton & Williams LLP

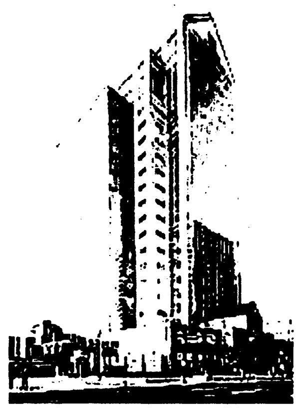
ATTACHMENT A

search



After more than three successful years as part of the E.ON family, LG&E Energy, the parent company of Louisville Gas and Electric Company, Kentucky Utilities Company and Western Kentucky Energy, is now E.ON U.S.

LG&E, KU, and WKE — the companies that customers are most familiar with — will continue to operate under their current identities. more



06.28.2006
LG&E Coal Ash Recycled; Land to be used for Green Space

06.27.2006
E.ON U.S. Capital Corp. Announces Pricing Of Tender Offer and Consent Solicitation

06.20.2006
LG&E Announces Regular Dividends On Preferred Stock

LG&E
- For the Home
- For the Business

KU/ODP
- For the Home
- For the Business

LG&E/KU Standards of Conduct

Effective September 22, 2004, E.ON U.S. and other U.S. energy companies must comply with new Federal Energy Regulatory Commission ("FERC") orders requiring organizational separation between transmission and energy and marketing affiliates.

Collectively, the new orders are referred to as the Standards of Conduct and are fundamentally based on two guiding principles. First, a Transmission Provider's employees engaged in transmission system operations must function independent from the employees of its Marketing and Energy Affiliates. Secondly, a Transmission Provider must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis and must not operate its transmission system to preferentially benefit its marketing or energy affiliates. The Final Rule requires organizational separation of all energy and marketing affiliates, including natural gas marketing affiliates, from the electric transmission function.

The Standards of Conduct require that a Transmission Provider must post certain information on its corporate website or its OASIS. Links to all of the requisite information, whether residing here or on the LG&E/KU page of the MISO OASIS, are provided below. Please contact the Chief Compliance Officer if you have any questions.

- How to Report a Potential Violation of the Standards of Conduct
- Request for Access to Transmission Control Center
- FERC Orders - Standard of Conduct Regulation (PDF)
- FERC Orders - Order No. 2004 (PDF)
- FERC Orders - Order No. 2004-A (PDF)
- FERC Orders - Order No. 2004-B (PDF)
- LG&E/KU Compliance Procedures (PDF)
- LG&E/KU February 2004 Compliance Filing (PDF)
- Chief Compliance Officer
- Marketing & Energy Affiliate Listing (PDF)
- Shared Facilities Listing
- Notices of Employee Transfers (PDF)
- Organizational Charts - Overall Corporate Structure (PDF)
- Organizational Charts - Chain of Command (PDF)
- Organizational Charts - Transmission Chain of Command
- Organizational Charts - Energy Marketing Chain of Command
- Organizational Charts - Job Titles & Descriptions (PDF)
- Potential Merger Partners as Affiliates (none at this time)
- Disclosure of Information (PDF)
- Voluntary Consent to Disclose Information (none at this time)
- Log of Tariff Administration Matters and Discounts
- MISO OASIS
- LG&E/KU page of MISO OASIS

Download PDF (103K)

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(m)
Sponsoring Witness: Valerie L. Scott

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission Form 1 (electric), Federal Energy Regulatory Commission Form 2 (gas), or Automated Reporting Management Information System Report (telephone) and Public Service Commission Form T (telephone).

Response:

KU's most recent FERC Form 1 for the year ended December 31, 2011, is attached.

THIS FILING IS		
Item 1: ☐ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

Public Service Commission of Kentucky

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Kentucky Utilities Company	**End of** 2011/Q4

KENTUCKY UTILITIES COMPANY

PUBLIC SERVICE COMMISSION OF KENTUCKY

PRINCIPAL PAYMENT AND INTEREST INFORMATION
FOR THE YEAR ENDING DECEMBER 31, 2011

1. Amount of Principal Payment during calendar year $ ______0.00

2. Is Principal current? (Yes) ____X_____ (No) __________

3. Is Interest current? (Yes) _____X_____ (No) __________

SERVICES PERFORMED BY
INDEPENDENT CERTIFIED PUBLIC ACCOUNTANT

Are your financial statements examined by a Certified Public Accountant?

(Yes) _____X_____ (No) __________

If yes, which service is performed?

Audit _____X____

Compilation _________

Review _________

Please enclose a copy of the accountant's report with annual report.

KENTUCKY UTILITIES COMPANY
ADDITIONAL INFORMATION TO BE FURNISHED WITH
2011 ANNUAL REPORT

ELECTRIC UTILITIES

Please furnish the following information, for Kentucky Operations only, and attach to your Annual Report:

Number of Rural Customers (Other than Farms)	INFORMATION NOT AVAILABLE
Number of Farms Served (A farm is any agricultural operating unit consisting of 3 acres of more)	INFORMATION NOT AVAILABLE
Number of KWH sold to all Rural Customers	INFORMATION NOT AVAILABLE
Total Revenue from all Rural Customers	INFORMATION NOT AVAILABLE

LINE DATA

Total number of Miles of Wire Energized (Located in Kentucky)	32,440
Total number of Miles of Pole line (Located in Kentucky)	20,465

Name of Counties in which you furnish Electric Service:
(If additional space is required, add additional sheet)

Adair	Campbell	Fayette	Harrison	Lincoln	Muhlenberg	Russell
Anderson	Carlisle	Fleming	Hart	Livington	Nelson	Scott
Ballard	Carroll	Franklin	Henderson	Lyon	Nicholas	Shelby
Barren	Casey	Fulton	Henry	Madison	Ohio	Spencer
Bath	Christian	Gallatin	Hickman	Marion	Oldham	Taylor
Bell	Clark	Garrard	Hopkins	Mason	Owen	Trimble
Bourbon	Clay	Grant	Jessamine	McCracken	Pendleton	Union
Boyle	Crittenden	Grayson	Knox	McCreary	Pulaski	Washington
Bracken	Daviess	Green	Larue	McLean	Robertson	Webster
Bullitt	Edmonson	Hardin	Laurel	Mercer	Rockcastle	Whitley
Caldwell	Estill	Harlan	Lee	Montgomery	Rowan	Woodford

(A) Based on Standard Industrial Classification (SIC) Major Groups 01 (Agricultural Production-Crops) and and 02 (Agricultural ProductionLivestock and Animal Specialties).

Kentucky Utilities Company
Supplemental Electric Information
Revenues, Customers and KWH Sales
For Reporting Year 2011

	Revenues	KWHs Sold	Customers
440 Residential	$ 493,162,201	6,145,624,184	421,248
442 Commercial & Industrial Sales			
Small(or Commercial)	$ 330,846,846	4,106,739,270	80,166
Large (or Industrial)	$ 364,814,037	6,450,370,176	2,282
444 Public St. & Highway Lighting	$ 10,752,068	48,773,795	1,230
445 Other Sales to Public Authorities	$ 109,191,697	1,568,592,285	6,660
446 Sales to Railroads and Railways	$ -	-	-
448 Interdepartmental Sales	$ -	-	-
TOTAL Sales to Ultimate Customers	$ 1,308,766,849	18,320,099,710	511,586
447 Sales for Resale	$ 140,153,792	3,125,213,063	28
449 Provision for Rate Refund	$ -		
TOTAL Sales of Electricity	$ 1,448,920,641	21,445,312,773	511,614

THIS PAGE MUST BE COMPLETED AND RETURNED WITH THE ANNUAL REPORT

** For Kentucky Operations Only

KENTUCKY UTILITIES COMPANY
NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES
SUPPLEMENTAL INFORMATION TO 2011 ANNUAL REPORT

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.

The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1.	Payroll Period Ended (Date)	12/31/2011
2.	Total Regular Full-Time Employees	943
3.	Total Part-Time and Temporary Employees	-
4.	Total Employees	943

Note: Number of electric employees includes both Kentucky and Virginia jurisdiction.

Additional Requested Information

Utility Name Kentucky Utilities Company

FEIN# (Federal Employer Identification Number)

6	1	-	0	2	4	7	5	7	0

Contact Person Eric Raible

Contact Person's E-Mail Address eric.raible@lge-ku.com

Utility's Web Address www.lge-ku.com

Please complete the above information, if it is available.

If there are multiple staff who may be contacts please include their names and e-mail addresses also.

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐ Resubmission No. ____	

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Kentucky Utilities Company	**End of** 2011/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

BLANK

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Kentucky Utilities Company	02 Year/Period of Report End of 2011/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 220 West Main Street, P.O. Box 32030, Louisville, KY 40202	
05 Name of Contact Person Eric Raible	06 Title of Contact Person Mgr- Regulatory Acct & Reprt
07 Address of Contact Person *(Street, City, State, Zip Code)* 220 West Main Street, P.O. Box 32030, Louisville, KY 40232	

08 Telephone of Contact Person, *Including Area Code* (502) 627-3426	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Kent W. Blake	03 Signature Kent W. Blake	04 Date Signed *(Mo, Da, Yr)* 04/17/2012
02 Title Chief Financial Officer		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	None
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	None
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	None
56	Amounts included in ISO/RTO Settlement Statements	397	
57	Purchase and Sale of Ancillary Services	398	
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	None
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	
63	Hydroelectric Generating Plant Statistics	406-407	
64	Pumped Storage Generating Plant Statistics	408-409	None
65	Generating Plant Statistics Pages	410-411	None
66	Transmission Line Statistics Pages	422-423	

BLANK

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Stockholders' Reports Check appropriate box:

[ ] Two copies will be submitted

[X] No annual report to stockholders is prepared

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Kent Blake, Chief Financial Officer
220 West Main Street
Louisville, KY 40202

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Kentucky August 17, 1912
Virginia December 1, 1991

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Respondent furnishes electric services in Kentucky, Virginia, and Tennessee.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [X] Yes...Enter the date when such independent accountant was initially engaged: 02/23/2011
(2) [ ] No

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2011/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Kentucky Utilities Company (KU) is a wholly-owned subsidiary of LG&E and KU Energy LLC. LG&E and KU Energy LLC is a wholly-owned subsidiary of PPL Corporation, based in Allentown, PA.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	CURRENT OFFICERS AT DECEMBER 31, 2011		
2	Chairman of the Board, President and		
3	Chief Executive Officer	Victor A. Staffieri	381,288
4	Executive Vice President, General Counsel,		
5	Corporate Secretary and Chief Compliance Officer	John R. McCall	235,332
6	Senior Vice President - Energy Delivery	Chris Hermann	146,875
7	Chief Financial Officer	S. Bradford Rives	176,305
8	Senior Vice President - Energy Services	Paul W. Thompson	206,699
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Schedule Page: 104 Line No.: 3 Column: c

Officers are employed by LG&E and KU Services Company. Amounts shown reflect the portion of their salary allocated to KU.

Schedule Page: 104 Line No.: 5 Column: b

John R. McCall's title changed to Executive Vice President, effective March 19, 2012.

Schedule Page: 104 Line No.: 7 Column: b

S. Bradford Rives was named Chief Administrative Officer and Kent W. Blake was named Chief Financial Officer effective February 1, 2012.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	CURRENT BOARD OF DIRECTORS AT DECEMBER 31, 2011	
2		
3	Victor A. Staffieri, Chairman of the Board, President	
4	and Chief Executive Officer	220 West Main Street, Louisville, KY 40202
5	John R. McCall, EVP, General Counsel, Corporate	
6	Secretary and Chief Compliance Officer	220 West Main Street, Louisville, KY 40202
7	S. Bradford Rives, Chief Financial Officer	220 West Main Street, Louisville, KY 40202
8	Chris Hermann, SVP - Energy Delivery	220 West Main Street, Louisville, KY 40202
9	Paul W. Thompson, SVP - Energy Services	220 West Main Street, Louisville, KY 40202
10	Paul A. Farr, EVP and Chief Financial Officer of PPL	2 North Ninth Street, Allentown, PA 18101
11	William H. Spence, Chief Executive Officer of PPL	2 North Ninth Street, Allentown, PA 18101
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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2011/Q4

FOOTNOTE DATA

Schedule Page: 105 Line No.: 11 Column: a

William H. Spence was named Chief Executive Officer of PPL in November 2011. He previously held the position of Executive Vice President and Chief Operating Officer of PPL.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Various	
2	Open Access Transmission Tariff (OATT)	
3	Attachment O	Docket No. ER11-2955
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5	OATT Schedule 1	Docket No. ER10-1509
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Schedule Page: 106 Line No.: 1 Column: a

Municipal	**Rate Schedule No. for Amended Agreement as Filed 4/30/09**
Barbourville	3rd Rev. 184
Bardstown	3rd Rev. 185
Bardwell	3rd Rev. 186
Benham	3rd Rev. 187
Berea	2nd Rev. 197
Corbin	3rd Rev. 188
Falmouth	3rd Rev. 189
Frankfort	3rd Rev. 190
Madisonville	3rd Rev. 161
Nicholasville	3rd Rev. 157
Paris	3rd Rev. 83
Providence	4th Rev. 195

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20110502-5547	05/02/2011	ER08-1588	Annual Updates to Generation	Various
2				Formula Rates	
3					
4					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	Not Applicable			
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. None.

2. None.

3. During November 2010, Kentucky Utilities Company (“KU”) transferred 149 railcars owned by KU to Trinity Industries Leasing Company as part of a lease transaction under which KU is leasing 150 new aluminum railcars. The railcars had an original value of $7,296,251 and a net book value of $1,258,141. KU received a trade-in allowance for the railcars of $774,800. KU has classified this trade-in allowance as prepaid rent as it will reduce the monthly lease payments over the life of the lease by this amount. KU will recognize a loss of $483,341, which is the difference between the net book value of the existing railcars and the trade-in allowance given by the lessor. This loss was recorded in Plant Account 102 (Electric Plant Purchased or Sold). The journal entries for this transaction were filed with the FERC on April 11, 2011.

   In September 2011, KU and Louisville Gas and Electric Company ("LG&E") entered into an agreement with Bluegrass Generation Company, L.L.C. for the purchase of three existing natural gas simple cycle combustion turbine units in LaGrange, Kentucky, aggregating approximately 495 MW, plus certain associated assets for a purchase price of $110 million. KU and LG&E will jointly acquire the assets as tenants in common, with KU and LG&E having 31% and 69% respective undivided interests. The purchase is subject to receipt of approvals from the Kentucky Public Service Commission, the Virginia Commission, the FERC, and other conditions. On November 14, 2011, a FERC application was submitted in Docket No.EC12-29, including draft accounting entries.

4. None of a material nature.

5. In 2011, 1.69 miles of transmission lines went into service. As these were interconnect transmission lines, no customers were added.

6. KU received FERC authorization in FERC Docket No. ES11-48-000 for up to $500 million in short-term debt through November 30, 2013. KU's money pool balance was zero and $10 million at December 31, 2011, and December 31, 2010, respectively.

   On November 1, 2010, KU entered into a new $400 million revolving credit facility maturing December 31, 2014. In October 2011, KU amended its syndicated credit facility. The amendment includes extending the expiration date from December 2014 to October 2016. Under this facility, KU continues to have the ability to make cash borrowings and to request the lenders to issue letters of credit. The facility is consistent with the above FERC authorization and was approved by the Kentucky Commission Order, Case No. 2010-00206, on September 30, 2010, by the Virginia Commission on October 19, 2010, in Case No. PUE-2010-00094 and Case No. PUE-2010-00130, and by the Tennessee Regulatory Authority on October 21, 2010 in Docket No. 10-00119. There was no balance outstanding under this facility at December 31, 2011, and December 31, 2010 although letters of credit totaling $198 million were issued under the facility at December 31, 2010.

   In April 2011, KU entered into a new letter of credit facility totaling approximately $198 million.

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Letters of credit totaling $198 million were outstanding under this facility at December 31, 2011. These letters of credit replaced prior letters of credit of the same amount issued under the revolving credit facility described above. The facility is consistent with the above FERC authorization and was approved by the Kentucky Commission Order, Case No. 2008-00309 on September 16, 2008, by the Virginia Commission on August 29, 2008, in Case No. PUE-2008-00077, and by the Tennessee Regulatory Authority on September 15, 2008 in Docket No. 08-00144.

7. None.

8. During the first quarter of 2011, exempt and non exempt employees received routine wage increases in accordance with annual salary reviews. During July 2011, KU hourly employees and employees represented by an USWA Local 9447 and by IBEW Local 2100 received a routine wage increase as a result of separate contract negotiations.

9. See Notes 4 and 11 of Notes to Financial Statements.

10. None.

11. N/A

12. See attached Notes to Financial Statements.

13. Edwin R. Staton was named Vice President of Transmission effective March 28, 2011. Brad Rives was named Chief Administrative Officer and Kent Blake was named Chief Financial Officer effective February 1, 2012. John R. McCall's title was changed to Executive Vice President and Gerald Reynolds was named General Counsel, Corporate Secretary and Chief Compliance Officer effective March 19, 2012.

14. KU is a participant in a cash pooling arrangement, but its proprietary capital ratio is above 30 percent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	6,443,488,241	5,542,351,018
3	Construction Work in Progress (107)	200-201	339,711,432	954,430,277
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,783,199,673	6,496,781,295
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,395,037,773	2,261,926,782
6	Net Utility Plant (Enter Total of line 4 less 5)		4,388,161,900	4,234,854,513
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		4,388,161,900	4,234,854,513
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		179,121	179,121
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	30,566,563	30,289,224
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	1,564
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		30,745,684	30,469,909
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		31,096,140	3,132,600
36	Special Deposits (132-134)		45,500	418,600
37	Working Fund (135)		39,030	39,025
38	Temporary Cash Investments (136)		43,674	200,847
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		71,373,905	87,296,102
41	Other Accounts Receivable (143)		13,700,580	28,510,674
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,004,312	6,041,458
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		39,616	11,996,433
45	Fuel Stock (151)	227	96,745,429	94,898,528
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	34,036,932	32,560,243
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	450,462	566,579

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	9,914,010	8,854,899
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		7,285,321	8,173,725
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		21,219	21,219
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		81,180,950	88,688,000
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		0	20,501
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	1,564
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		343,968,456	359,334,953
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		17,191,160	16,587,219
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	280,059,195	231,807,962
73	Prelim. Survey and Investigation Charges (Electric) (183)		4,051,457	3,594,690
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	5,281
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	788,507,896	834,531,734
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		11,775,117	12,380,090
82	Accumulated Deferred Income Taxes (190)	234	144,267,426	115,372,945
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,245,852,251	1,214,279,921
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,008,728,291	5,838,939,296

Schedule Page: 110 Line No.: 2 Column: c

This Form 1 is filed reflecting purchase accounting consistent with final accounting entries approved on October 14, 2011, in Docket No. AC11-83-000.

Schedule Page: 110 Line No.: 2 Column: d

The majority of the note below provides a summary of all the purchase accounting included in the financial statements for Kentucky Utilities Company ("KU"). These descriptions are provided as early as possible in this document as these descriptions relate to many separate disclosures of purchase accounting adjustments and are intended to prevent repetition throughout the document.

On November 1, 2010, PPL Corporation ("PPL") completed its acquisition of LG&E and KU Energy LLC (“LKE”) and its subsidiaries. The push-down basis of accounting was used to record the fair value adjustments of assets and liabilities on LKE at the acquisition date. PPL paid a cash consideration for LKE and its subsidiaries of $2,493 million as well as a capital contribution on November 1, 2010, of $1,565 million; included within this transaction was the consideration paid for KU of $2,656 million. The allocation of the KU purchase price was based on the fair value of assets acquired and liabilities assumed.

The allocation of the purchase price to the fair value of assets acquired and liabilities assumed is as follows (in millions):

Current assets	$ 364
Investments	30
Property, plant and equipment	4,531
Other intangible assets	178
Regulatory and other non-current assets	274
Current liabilities (excluding current portion of long-term debt)	(367)
Affiliated debt	(1,331)
Debt (current and non-current)	(352)
Other non-current liabilities	(1,278)
Net identifiable assets acquired	2,049
Goodwill	607
Total purchase price	$ 2,656

Goodwill represents value paid for the rate regulated business of KU, which is located in a defined service area with a constructive regulatory environment, which provides for future investment, earnings and cash flow growth, as well as the assembled workforce. KU’s franchise values are being attributed to the going concern value of the business, and thus were recorded as goodwill rather than a separately identifiable intangible asset. None of the goodwill recognized is deductible for income tax purposes or included in regulated customer rates.

Adjustments to KU’s assets and liabilities that contributed to goodwill were as follows:

The fair value adjustment on the EEI investment was calculated using the discounted cash flow valuation method. The result was an increase in KU’s value of the investment in EEI; the fair value of EEI was calculated to be $30 million and a fair value adjustment of $18 million was recorded on KU. The fair value adjustment to EEI is amortized over the expected remaining useful life of plant and equipment at EEI, which is estimated to be over 20 years.

The pollution control bonds had a fair value adjustment of $1 million. All variable bonds were valued at par while the fixed rate bonds were valued with a yield curve based on average credit spreads for similar bonds.

As a result of the purchase accounting associated with the acquisition, the following items had a fair value adjustment but no effect on goodwill as the offset was either a regulatory asset or liability. The regulatory asset or liability has been recorded to eliminate any ratemaking impact of the fair value adjustments:

- The value of OVEC was determined to be $39 million based upon an announced transaction by another owner. KU's stock was valued at less than $1 million and the power purchase agreement has been valued at $39 million. An intangible asset was recorded with the offset to regulatory liability and will be amortized using the units of production method until March 2026, the end of the purchase agreement at the time of the acquisition.
- KU recorded an emission allowance intangible asset and regulatory liability as the result of adjusting the fair value of the emission allowances at KU. The emission allowance fair value of $9 million represents allocated and purchased SO_2 and NOx emission allowances that are unused as of the valuation date or allocated for use in future years. KU had previously recorded emission allowances as other materials and supplies. The emission allowance fair value adjustment is amortized as the emission allowances are consumed, which is expected to occur through 2040.
- KU recorded a coal contract intangible asset of $145 million and non-current liability of $22 million on the Balance Sheet. An offsetting regulatory asset was recorded for those contracts with unfavorable terms relative to market. An offsetting regulatory liability was recorded for those contracts that had favorable terms relative to market. All coal contracts held by KU, wherein it had entered into arrangements to buy amounts of coal at fixed prices from counterparties at a future date, were fair valued. The intangible assets and other liabilities, as well as the regulatory assets and liabilities, are being amortized over the same terms as the related contracts, which expire through 2016.

The fair value of intangible assets and liabilities (e.g. contracts that have favorable or unfavorable terms relative to market), including coal contracts and power purchase agreements, as well as emission allowances, have been reflected on the Balance Sheet with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the acquisition. As a result, management believes the regulatory assets and liabilities created to offset the fair value adjustments meet the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. KU's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU also considered whether a separate fair value should be assigned to KU's rights to operate within its various electric service areas but concluded that these rights only provided the opportunity to earn a regulated return and barriers to market entry, which in management's judgment is not considered a separately identifiable intangible asset under applicable accounting guidance; rather, it is considered going-concern value, or goodwill.

Schedule Page: 110 Line No.: 21 Column: c

The balance in Investment in Subsidiary Companies (123.1) was adjusted due to the purchase of KU by PPL in November 2010. To reflect the fair value in Investment in Subsidiary Companies, a step-up in value compared to the net book value of the investment in EEI was recorded. The step-up in value was assumed to relate to EEI's plant and is amortized over the average life of EEI's plant assets. The following reflects the purchase accounting adjustment:

Investment in Subsidiary Companies (123.1) Without Purchase Accounting	$ 13,878,645
Purchase Accounting Adjustment	17,721,683
2011 Amortization of Purchase Accounting Adjustment	(886,084)
2010 Amortization of Purchase Accounting Adjustment	(147,681)
Total for Investment in Subsidiary Companies (123.1)	$ 30,566,563

Schedule Page: 110 Line No.: 21 Column: d

The balance in Investment in Subsidiary Companies (123.1) was adjusted due to the purchase of KU by PPL in November 2010. To reflect the fair value in Investment in Subsidiary Companies, a step-up in value compared to the net book value of the investment in EEI was recorded. The step-up in value was assumed to relate to EEI's plant and is amortized over the average life of EEI's plant assets. The following reflects the purchase accounting adjustment:

Investment in Subsidiary Companies (123.1) Without Purchase Accounting	$ 12,715,222
Purchase Accounting Adjustment	17,721,683
Amortization of Purchase Accounting Adjustment	(147,681)
Total for Investment in Subsidiary Companies (123.1)	$ 30,289,224

Schedule Page: 110 Line No.: 40 Column: c

The balance in Customer Accounts Receivable (142) was adjusted due to the purchase of KU by PPL in November 2010. To reflect the fair value of Customer Accounts Receivable, KU netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of the acquisition date. The fair value adjustment is amortized over the period accounts receivable are written off. See footnote for Page 110, Line 42, Column c. The following reflects the purchase accounting adjustment:

Customer Accounts Receivable (142) Without Purchase Accounting	$ 71,373,905
Purchase Accounting Adjustment	(2,205,992)
2011 Amortization of Purchase Accounting Adjustment	1,102,996
2010 Amortization of Purchase Accounting Adjustment	1,102,996
Total for Customer Accounts Receivable (142)	$ 71,373,905

Schedule Page: 110 Line No.: 40 Column: d

The balance in Customer Accounts Receivable (142) was adjusted due to the purchase of KU by PPL in November 2010. To reflect the fair value of Customer Accounts Receivable, KU netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of the acquisition date. The fair value adjustment is amortized over the period accounts receivable are written off. See footnote for Page 110, Line 42, Column d. The following reflects the purchase accounting adjustment:

Customer Accounts Receivable (142) Without Purchase Accounting	$ 88,399,098
Purchase Accounting Adjustment	(2,205,992)
Amortization of Purchase Accounting Adjustment	1,102,996
Total for Customer Accounts Receivable (142)	$ 87,296,102

Schedule Page: 110 Line No.: 41 Column: c

The balance in Other Accounts Receivable (143) was adjusted due to the purchase of KU by PPL in November 2010. To reflect the fair value of Other Accounts Receivable, KU netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of the acquisition date. The fair value adjustment is amortized over the period the accounts receivable are written off. See footnote for Page 110, Line 42, Column c. The following reflects the purchase accounting adjustment:

Other Accounts Receivable (143) Without Purchase Accounting	$ 13,700,580
Purchase Accounting Adjustment	(4,669,408)

2011 Amortization of Purchase Accounting Adjustment	4,643,204
2010 Amortization of Purchase Accounting Adjustment	26,204
Total for Other Accounts Receivable (143)	$ 13,700,580

Schedule Page: 110 Line No.: 41 Column: d

The balance in Other Accounts Receivable (143) was adjusted due to the purchase of KU by PPL in November 2010. To reflect the fair value of Other Accounts Receivable, KU netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of the acquisition date. The fair value adjustment is amortized over the period the accounts receivable are written off. See footnote for Page 110, Line 42, Column d. The following reflects the purchase accounting adjustment:

Other Accounts Receivable (143) Without Purchase Accounting	$ 33,153,878
Purchase Accounting Adjustment	(4,669,408)
Amortization of Purchase Accounting Adjustment	26,204
Total for Other Accounts Receivable (143)	$ 28,510,674

Schedule Page: 110 Line No.: 42 Column: c

The balance in Accumulated Provision For Uncollectible Accounts (144) was adjusted due to the purchase of KU by PPL in November 2010. To reflect the fair value of Customer Accounts Receivable and Other Accounts Receivable, KU netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of the acquisition date. Amortization of purchase accounting entries in accounts 142 and 143 is offset in this account. The following reflects the purchase accounting adjustment:

Accum. Prov. For Uncollectible Acct. (144) Without Purchase Accounting	$ 2,004,312
Purchase Accounting Adjustment	(6,875,400)
2011 Amortization of Purchase Accounting Adjustment	5,746,200
2010 Amortization of Purchase Accounting Adjustment	1,129,200
Total for Accum. Prov. For Uncollectible Acct. (144)	$ 2,004,312

Schedule Page: 110 Line No.: 42 Column: d

The balance in Accumulated Provision For Uncollectible Accounts (144) was adjusted due to the purchase of KU by PPL in November 2010. To reflect the fair value of Customer Accounts Receivable and Other Accounts Receivable, KU netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of the acquisition date. Amortization of purchase accounting entries in accounts 142 and 143 is offset in this account. The following reflects the purchase accounting adjustment:

Accum. Prov. For Uncollectible Acct. (144) Without Purchase Accounting	$ 11,787,658
Purchase Accounting Adjustment	(6,875,400)
Amortization of Purchase Accounting Adjustment	1,129,200
Total for Accum. Prov. For Uncollectible Acct. (144)	$ 6,041,458

Schedule Page: 110 Line No.: 44 Column: c

The decrease is due to intercompany tax settlements that were outstanding at December 31, 2010.

Schedule Page: 110 Line No.: 63 Column: c

All derivative transactions were liquidated and settled in the fourth quarter of 2011 due to MF Global's bankruptcy.

Schedule Page: 110 Line No.: 69 Column: c

The balance in Unamortized Debt Expenses (181) was adjusted due to the purchase of KU by PPL in November 2010, as these costs are considered to have no fair value in purchase accounting under US GAAP. However, since KU receives recovery of these costs in rates through the embedded cost of capital, the balance of $4,662,536 was reclassified to Other Regulatory Assets (182.3) in purchase accounting. The balance continues to amortize over the remaining term of the debt. The following reflects the purchase accounting adjustment:

Unamortized Debt Expense (181) Without Purchase Accounting	$ 21,600,912
Purchase Accounting Adjustment	(4,662,536)
2011 Amortization of Purchase Accounting Adjustment	216,672
2010 Amortization of Purchase Accounting Adjustment	36,112
Total Unamortized Debt Expenses (181)	$ 17,191,160

Schedule Page: 110 Line No.: 69 Column: d

The balance in Unamortized Debt Expenses (181) was adjusted due to the purchase of KU by PPL in November 2010, as these costs are considered to have no fair value in purchase accounting under US GAAP. However, since KU receives recovery of these costs in rates through the embedded cost of capital, the balance of $4,662,536 was reclassified to Other Regulatory Assets (182.3) in purchase accounting. The balance continues to amortize over the remaining term of the debt. The following reflects the purchase accounting adjustment:

Unamortized Debt Expense (181) Without Purchase Accounting	$ 21,213,643
Purchase Accounting Adjustment	(4,662,536)
Amortization of Purchase Accounting Adjustment	36,112
Total Unamortized Debt Expenses (181)	$ 16,587,219

First mortgage bonds were issued November 16, 2010, resulting in debt issuance expenses of $12,620,048 to be amortized over the life of the related issues, of which $119,194 was amortized through December 31, 2010. A revolving credit facility was set up on November 1, 2010, resulting in setup fees of $4,255,435 to be amortized over the term of the credit facility, of which $169,070 was amortized through December 31, 2010.

Schedule Page: 110 Line No.: 72 Column: c

The balance in Other Regulatory Assets (182.3) was adjusted to reflect regulatory offsets due to the purchase of KU by PPL in November 2010. The adjustments represent the fair value of coal supply contracts based upon the difference between estimated market prices of the coal to be purchased and the actual prices in the contracts, the reclassification of Unamortized Debt Expenses, and the fair value of a lease contract based upon the difference between the estimated market price of the leased property and the actual lease costs. The balances will be amortized as the underlying purchase accounting adjustments are amortized. See footnotes for Page 110, Line 69, Column c and Page 112, Line 59, Column c.

Other Regulatory Assets (182.3) Without Purchase Accounting	$ 268,828,297
Purchase Accounting Adjustment – unamortized debt expenses	4,662,536
2011 Amortization of Purchase Accounting Adjustment – unamortized debt expenses	(216,672)
2010 Amortization of Purchase Accounting Adjustment – unamortized debt expenses	(36,112)
Purchase Accounting Adjustment – coal supply contracts	22,605,479
2011 Amortization of Purchase Accounting Adjustment – coal supply contracts	(11,735,750)
2010 Amortization of Purchase Accounting Adjustment – coal supply contracts	(4,728,247)
Purchase Accounting Adjustments – rent commitments	900,950
2011 Amortization of Purchase Accounting Adjustment – rent commitments	(221,286)

Total for Other Regulatory Assets (182.3)	$ 280,059,195

Schedule Page: 110 Line No.: 72 Column: d

The balance in Other Regulatory Assets (182.3) was adjusted to reflect regulatory offsets due to the purchase of KU by PPL in November 2010. The adjustments represent the fair value of coal supply contracts based upon the difference between estimated market prices of the coal to be purchased and the actual prices in the contracts, the reclassification of Unamortized Debt Expenses, and the fair value of a lease contract based upon the difference between the estimated market price of the leased property and the actual lease costs. The balances will be amortized as the underlying purchase accounting adjustments are amortized. See footnotes for Page 110, Line 69, Column d and Page 112, Line 59, Column d.

Other Regulatory Assets (182.3) Without Purchase Accounting	$ 208,403,356
Purchase Accounting Adjustment – unamortized debt expenses	4,662,536
Amortization of Purchase Accounting Adjustment – unamortized debt expenses	(36,112)
Purchase Accounting Adjustment – coal supply contracts	22,605,479
Amortization of Purchase Accounting Adjustment – coal supply contracts	(4,728,247)
Purchase Accounting Adjustments – rent commitments	900,950
Total for Other Regulatory Assets (182.3)	$ 231,807,962

Schedule Page: 110 Line No.: 78 Column: c

The balance in Miscellaneous Deferred Debits (186) was adjusted due to the purchase of KU by PPL in November 2010. The account was adjusted for coal supply contracts, a power purchase contract, emission allowances and goodwill attributed to KU. Coal supply contracts were adjusted to reflect the fair value based upon the difference between estimated market prices of the coal to be purchased and the actual prices in the contracts. Using the offer of a transaction by another owner as an indication of the fair value, the fair value of the power purchase contract was calculated using a weighted average of the announced offer and the allotted megawatt multiplied by KU’s megawatt capacity. The value assigned to the purchase power contract was the difference between KU’s original investment and the $39 million for KU. Emission allowances were adjusted to current market prices of SO2 and NOx at the acquisition date.

The adjustments for coal supply contracts, emission allowances and the power purchase contract were recorded with a regulatory liability offset since the actual costs of these contracts are recoverable through rate mechanisms. The value of the coal contracts is amortized ratably by year over the life of the contracts. The value of emission allowances is amortized over the life of the allowances. The value of the power purchase agreement is amortized over the term of the contract, ending in March 2026. The value assigned to goodwill will not be amortized. See footnote for Page 112, Line 60, Column c. The following reflects the purchase accounting adjustments:

Miscellaneous Deferred Debits (186) Without Purchase Accounting	$ 41,140,563
Purchase Accounting Adjustment – purchase power contract	38,582,028
2011 Amortization of Purchase Accounting Adjustment – purchase power contract	(2,432,244)
2010 Amortization of Purchase Accounting Adjustment – purchase power contract	(464,152)
Purchase Accounting Adjustment – emission allowances	9,259,090
2011 Amortization of Purchase Accounting Adjustment – emission allowances	(5,771,743)

2010 Amortization of Purchase Accounting Adjustment – emission allowances	(983,780)
Purchase Accounting Adjustment – coal supply contracts	144,919,879
2011 Amortization of Purchase Accounting Adjustment – coal supply contracts	(39,807,234)
2010 Amortization of Purchase Accounting Adjustment – coal supply contracts	(3,338,879)
Goodwill	607,404,368
Total for Miscellaneous Deferred Debits (186)	$ 788,507,896

Schedule Page: 110 Line No.: 78 Column: d

The balance in Miscellaneous Deferred Debits (186) was adjusted due to the purchase of KU by PPL in November 2010. The account was adjusted for coal supply contracts, a power purchase contract, emission allowances and goodwill attributed to KU. Coal supply contracts were adjusted to reflect the fair value based upon the difference between estimated market prices of the coal to be purchased and the actual prices in the contracts. Using the offer of a transaction by another owner as an indication of the fair value, the fair value of the power purchase contract was calculated using a weighted average of the announced offer and the allotted megawatt multiplied by KU's megawatt capacity. The value assigned to the purchase power contract was the difference between KU's original investment and the $39 million for KU. Emission allowances were adjusted to current market prices of SO2 and NOx at the acquisition date.

The adjustments for coal supply contracts, emission allowances and the power purchase contract were recorded with a regulatory liability offset since the actual costs of these contracts are recoverable through rate mechanisms. The value of the coal contracts is amortized ratably by year over the life of the contracts. The value of emission allowances is amortized over the life of the allowances. The value of the power purchase agreement is amortized over the term of the contract, ending in March 2026. The value assigned to goodwill will not be amortized. See footnote for Page 112, Line 60, Column d. The following reflects the purchase accounting adjustments:

Miscellaneous Deferred Debits (186) Without Purchase Accounting	$ 39,153,180
Purchase Accounting Adjustment – purchase power contract	38,582,028
Amortization of Purchase Accounting Adjustment – purchase power contract	(464,152)
Purchase Accounting Adjustment – emission allowances	9,259,090
Amortization of Purchase Accounting Adjustment – emission allowances	(983,780)
Purchase Accounting Adjustment – coal supply contracts	144,919,879
Amortization of Purchase Accounting Adjustment – coal supply contracts	(3,338,879)
Goodwill	607,404,368
Total for Miscellaneous Deferred Debits (186)	$ 834,531,734

Schedule Page: 110 Line No.: 82 Column: c

The balance in Accumulated Deferred Income Taxes (190) was adjusted due to the purchase of KU by PPL in November 2010. The purchase accounting adjustments were to reflect the deferred income tax impact of purchase accounting adjustments related to fixed interest rate pollution control bonds, coal supply contracts and a lease contract, and regulatory liabilities for a power purchase contract, emission allowances and coal supply contracts as of the acquisition date. The deferred income taxes are amortized as the underlying purchase accounting adjustments are amortized. See footnotes for Page 112, Line 21, Column c; Page 112, Line 59, Column c; and, Page 112, Line 60, Column c. The following reflects the purchase accounting adjustments:

Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$ 86,746,693
Purchase Accounting Adjustment – pollution control bonds	451,806
2011 Amortization of Purchase Accounting Adjustment – pollution control bonds	(25,793)
2010 Amortization of Purchase Accounting Adjustment – pollution control bonds	(4,299)
Purchase Accounting Adjustment – regulatory liability for power purchase contract	15,008,409
2011 Amortization of Purchase Accounting Adjustment – regulatory liability for power purchase contract	(946,143)
2010 Amortization of Purchase Accounting Adjustment – regulatory liability for power purchase contract	(180,555)
Purchase Accounting Adjustment – regulatory liability for emission allowances	3,601,785
2011 Amortization of Purchase Accounting Adjustment – regulatory liability for emission allowances	(2,245,208)
2010 Amortization of Purchase Accounting Adjustment – regulatory liability for emission allowances	(382,690)
Purchase Accounting Adjustment – regulatory liability for coal supply contracts	56,373,833
2011 Amortization of Purchase Accounting Adjustment – regulatory liability for coal supply contracts	(15,485,014)
2010 Amortization of Purchase Accounting Adjustment – regulatory liability for coal supply contracts	(1,298,823)
Purchase Accounting Adjustment – coal supply contracts	8,793,531
2011 Amortization of Purchase Accounting Adjustment – coal supply contracts	(4,565,207)
2010 Amortization of Purchase Accounting Adjustment – coal supply contracts	(1,839,288)
Purchase Accounting Adjustment – rent commitment	350,470
2011 Amortization of Purchase Accounting Adjustment – rent commitment	(73,783)
2010 Amortization of Purchase Accounting Adjustment – rent commitment	(12,298)
Total for Accumulated Deferred Income Taxes (190)	$ 144,267,426

Schedule Page: 110 Line No.: 82 Column: d

The balance in Accumulated Deferred Income Taxes (190) was adjusted due to the purchase of KU by PPL in November 2010. The purchase accounting adjustments were to reflect the deferred income tax impact of purchase accounting adjustments related to fixed interest rate pollution control bonds, coal supply contracts and a lease contract, and regulatory liabilities for a power purchase contract, emission allowances and coal supply contracts as of the acquisition date. The deferred income taxes are amortized as the underlying purchase accounting adjustments are amortized. See footnotes for Page 112, Line 21, Column d; Page 112, Line 59, Column d; and, Page 112, Line 60, Column d. The following reflects the purchase accounting adjustments:

Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$34,511,064
Purchase Accounting Adjustment – pollution control bonds	451,806
Amortization of Purchase Accounting Adjustment – pollution control bonds	(4,299)
Purchase Accounting Adjustment – regulatory liability for power purchase contract	15,008,409
Amortization of Purchase Accounting Adjustment – regulatory liability for power purchase contract	(180,555)

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Purchase Accounting Adjustment – regulatory liability for emission allowances	3,601,785
Amortization of Purchase Accounting Adjustment – regulatory liability for emission allowances	(382,690)
Purchase Accounting Adjustment – regulatory liability for coal supply contracts	56,373,833
Amortization of Purchase Accounting Adjustment – regulatory liability for coal supply contracts	(1,298,823)
Purchase Accounting Adjustment – coal supply contracts	8,793,531
Amortization of Purchase Accounting Adjustment – coal supply contracts	(1,839,288)
Purchase Accounting Adjustment – rent commitment	350,470
Amortization of Purchase Accounting Adjustment – rent commitment	(12,298)
Total for Accumulated Deferred Income Taxes (190)	$115,372,945

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2011/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	308,139,978	308,139,978
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	2,348,446,834	2,348,446,834
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	321,289	321,289
11	Retained Earnings (215, 215.1, 216)	118-119	88,297,104	35,351,542
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	1,081,010	43,895
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-467,077	-2,854
16	Total Proprietary Capital (lines 2 through 15)		2,745,176,560	2,691,658,106
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,850,779,405	1,850,779,405
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	1,084,098	1,150,404
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		10,187,844	10,823,094
24	Total Long-Term Debt (lines 18 through 23)		1,841,675,659	1,841,106,715
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		2,695,348	2,422,714
29	Accumulated Provision for Pensions and Benefits (228.3)		151,503,931	180,134,598
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	902
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		61,789,582	53,981,306
35	Total Other Noncurrent Liabilities (lines 26 through 34)		215,988,861	236,539,520
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		119,658,899	76,307,787
39	Notes Payable to Associated Companies (233)		0	10,434,000
40	Accounts Payable to Associated Companies (234)		33,178,775	45,351,362
41	Customer Deposits (235)		22,862,412	22,839,133
42	Taxes Accrued (236)	262-263	10,729,938	24,614,783
43	Interest Accrued (237)		10,619,839	8,149,642
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		3,805,278	4,205,425
48	Miscellaneous Current and Accrued Liabilities (242)		15,371,962	15,078,609
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	229,225
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	902
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		216,227,103	207,209,064
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		3,155,939	2,869,274
57	Accumulated Deferred Investment Tax Credits (255)	266-267	101,407,768	104,094,169
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	13,766,748	27,238,013
60	Other Regulatory Liabilities (254)	278	248,276,621	243,086,816
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		495,624,689	346,844,638
64	Accum. Deferred Income Taxes-Other (283)		127,428,343	138,292,981
65	Total Deferred Credits (lines 56 through 64)		989,660,108	862,425,891
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,008,728,291	5,838,939,296

Schedule Page: 112 Line No.: 7 Column: c

The balance in Other Paid-in Capital (208-211) was adjusted due to the purchase of KU by PPL in November 2010. To reflect the fair value, the balance was adjusted for a step-up in value compared to the net book value of the investment in EEI net of deferred taxes, the fixed rate pollution control bonds net of taxes and goodwill. The balance also includes elimination of Retained Earnings (215, 215.1, 216) at October 31, 2010. See footnotes for Page 110, Lines 21, Column c, Page 110, Line 78, Column c, Page 110, Line 82, Column c, Page 112, Line 11, Column c, Page 112, Line 21, Column c and Page 112, Line 64, Column c. The following reflects the purchase accounting adjustment:

Other Paid-in Capital (208-211) Without Purchase Accounting	$ 315,858,083
Purchase Accounting Adjustment - goodwill	607,404,368
Purchase Accounting Adjustment – EEI investment	7,569,645
Purchase Accounting Adjustment – pollution control bonds	(709,649)
Purchase Accounting Adjustment – prior retained earnings	1,418,324,387
Total for Other Paid-in Capital (208-211)	$ 2,348,446,834

Schedule Page: 112 Line No.: 7 Column: d

The balance in Other Paid-in Capital (208-211) was adjusted due to the purchase of KU by PPL in November 2010. To reflect the fair value, the balance was adjusted for a step-up in value compared to the net book value of the investment in EEI net of deferred taxes, the fixed rate pollution control bonds net of taxes and goodwill. The balance also includes elimination of Retained Earnings (215, 215.1, 216) at October 31, 2010. See footnotes for Page 110, Lines 21, Column d, Page 110, Line 78, Column d, Page 110, Line 82, Column d, Page 112, Line 11, Column d, Page 112, Line 21, Column d and Page 112, Line 64, Column d. The following reflects the purchase accounting adjustment:

Other Paid-in Capital (208-211) Without Purchase Accounting	$ 315,858,083
Purchase Accounting Adjustment - goodwill	607,404,368
Purchase Accounting Adjustment – EEI investment	7,569,645
Purchase Accounting Adjustment – pollution control bonds	(709,649)
Purchase Accounting Adjustment – prior retained earnings	1,418,324,387
Total for Other Paid-in Capital (208-211)	$ 2,348,446,834

Schedule Page: 112 Line No.: 11 Column: c

The balance in Retained Earnings (215, 215.1, 216) was adjusted due to the purchase of KU by PPL in November 2010. The adjustment eliminated Retained Earnings at October 31, 2010 and included amortization of purchase accounting adjustments recorded as of the acquisition date. See footnotes for Page 112, Line 7, Column c; Page 114, Line 4, Column c; Page 114, Line 17, Column c; Page 114, Line 18, Column c; Page 114, Line 36, Column c and Page 114, Line 62, Column c. The following reflects the purchase accounting adjustment:

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$ 1,490,663,791
Elimination of Retained Earnings	(1,404,083,567)
2011 Amortization of Purchase Accounting Adjustment – rent commitment (net of deferred taxes of $(12,297))	(19,315)
2010 Amortization of Purchase Accounting Adjustment – rent commitment (net of deferred taxes of $12,297)	19,315
2011 Amortization of Purchase Accounting Adjustment – pollution control bonds (net of deferred taxes of $25,793)	40,513
2010 Amortization of Purchase Accounting Adjustment – pollution control bonds (net of deferred taxes of	

$4,299)	6,752
2011 Deferred Tax on Amortization of Purchase Accounting Adjustment – EEI investment (see Line 12 Column c footnote for related Purchase Accounting Adjustment)	344,678
2010 Deferred Tax on Amortization of Purchase Accounting Adjustment – EEI investment (see Line 12 Column c footnote for related Purchase Accounting Adjustment)	57,448
Eliminate Deferred Tax on Purchase Accounting Adjustment – Other Comprehensive Income	1,267,489
Total for Retained Earnings (215, 215.1, 216)	$ 88,297,104

Schedule Page: 112 Line No.: 11 Column: d

The balance in Retained Earnings (215, 215.1, 216) was adjusted due to the purchase of KU by PPL in November 2010. The adjustment eliminated Retained Earnings at October 31, 2010 and included amortization of purchase accounting adjustments recorded as of the acquisition date. See footnotes for Page 112, Line 7, Column d. The following reflects the purchase accounting adjustment:

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$ 1,439,351,594
Elimination of Retained Earnings	(1,404,083,567)
2010 Amortization of Purchase Accounting Adjustment – rent commitment (net of deferred taxes of $12,297)	19,315
2010 Amortization of Purchase Accounting Adjustment – pollution control bonds (net of deferred taxes of $4,299)	6,752
2010 Deferred Tax on Amortization of Purchase Accounting Adjustment – EEI investment (see Line 12 Column d footnote for related Purchase Accounting Adjustment)	57,448
Total for Retained Earnings (215, 215.1, 216)	$ 35,351,542

Schedule Page: 112 Line No.: 12 Column: c

The balance in Unappropriated Undistributed Subidiary Earnings (216.1) was adjusted for Equity in Earnings for year (418.1) due to the purchase of KU by PPL in November 2010. This adjustment represents the amortization of KU’s purchase accounting adjustment related to KU’s investment in EEI:

Unappropriated Undistributed Subsidary Earnings (216.1) Without Purchase Accounting	$ 16,355,595
Purchase Accounting Adjustment	(14,240,820)
2011 Amortization of Purchase Accounting Adjustment (see Line 11 Column c footnote for related deferred tax)	(886,084)
2010 Amortization of Purchase Accounting Adjustment (see Line 11 Column c footnote for related deferred tax)	(147,681)
Total for Undistributed Subsidary Earnings (216.1)	$ 1,081,010

Schedule Page: 112 Line No.: 12 Column: d

The balance in Unappropriated Undistributed Subidiary Earnings (216.1) was adjusted for Equity in Earnings for year (418.1) due to the purchase of KU by PPL in November 2010. This adjustment represents the amortization of KU’s purchase accounting adjustment related to KU’s investment in Electric Energy, Inc:

Unappropriated Undistributed Subsidary Earnings (216.1) Without Purchase Accounting	$ 14,432,396
Purchase Accounting Adjustment	(14,240,820)
2010 Amortization of Purchase Accounting Adjustment (see Line 11 Column d footnote for related deferred tax)	(147,681)

Total for Undistributed Subsidary Earnings (216.1)	$	43,895

Schedule Page: 112 Line No.: 15 Column: c

The balance in Accumulated Other Comprehensive Income (219) was adjusted due to the purchase of KU by PPL in November 2010. The adjustment eliminated EEI's Accumulated Other Comprehensive Income to Other Paid-In Capital (211) related to its pension and postretirement plans. See footnote for Page 110, Line 21, Column c, Page 112, Line 7, Column c and Page 112, Line 64, Column c. The following reflects the purchase accounting adjustment:

Accumulated Other Comprehensive Income (219) Without Purchase Accounting	$	(2,457,900)
Purchase Accounting Adjustment		1,990,823
Total for Accumulated Other Comprehensive Income (219)	$	(467,077)

Schedule Page: 112 Line No.: 15 Column: d

The balance in Accumulated Other Comprehensive Income (219) was adjusted due to the purchase of KU by PPL in November 2010. The adjustment eliminated EEI's Accumulated Other Comprehensive Income to Other Paid-In Capital (211) related to its pension and postretirement plans. See footnote for Page 110, Line 21, Column d, Page 112, Line 7, Column d and Page 112, Line 64, Column d. The following reflects the purchase accounting adjustment:

Accumulated Other Comprehensive Income (219) Without Purchase Accounting	$	(1,993,677)
Purchase Accounting Adjustment		1,990,823
Total for Accumulated Other Comprehensive Income (219)	$	(2,854)

Schedule Page: 112 Line No.: 21 Column: c

The balance in Other Long-Term Debt (224) was adjusted due to the purchase of KU by PPL in November 2010. The balance was adjusted to reflect the fair value of the fixed rate pollution control bonds as of the acquisition date. The adjustment is the difference between the market value of the bonds using a market interest rate and the actual interest rate. The adjustment will be amortized over the remaining life of the bonds. The following reflects the purchase accounting adjustment:

Other Long-Term Debt (224) Without Purchase Accounting	$	-
Purchase Accounting Adjustment		1,161,455
2011 Amortization of Purchase Accounting Adjustment		(66,306)
2010 Amortization of Purchase Accounting Adjustment		(11,051)
Total for Other Long-Term Debt (224)	$	1,084,098

Schedule Page: 112 Line No.: 21 Column: d

The balance in Other Long-Term Debt (224) was adjusted due to the purchase of KU by PPL in November 2010. The balance was adjusted to reflect the fair value of the fixed rate pollution control bonds as of the acquisition date. The adjustment is the difference between the market value of the bonds using a market interest rate and the actual interest rate. The adjustment will be amortized over the remaining life of the bonds. The following reflects the purchase accounting adjustment:

Other Long-Term Debt (224) Without Purchase Accounting	$	-
Purchase Accounting Adjustment		1,161,455
Amortization of Purchase Accounting Adjustment		(11,051)
Total for Other Long-Term Debt (224)	$	1,150,404

Schedule Page: 112 Line No.: 39 Column: c

Balance represents drawdown of money pool in fourth quarter 2010 paid off during the first quarter of 2011.

Schedule Page: 112 Line No.: 50 Column: c

All derivative transactions were liquidated and settled in the fourth quarter 2011 due to MF Global's bankruptcy.

Schedule Page: 112 Line No.: 59 Column: c

The balance in Other Deferred Credits (253) was adjusted due to the purchase of KU by PPL in November 2010. The adjustments represent the fair value of certain coal supply contracts based upon the difference between estimated market prices of the coal to be purchased and the actual prices in the contracts and the fair value of a lease contract based upon the difference between the estimated market price of the leased property and the actual lease costs. The adjustments were recorded with a regulatory liability offset since the actual costs of these contracts are recoverable through rate mechanisms. The value of the coal contracts is amortized ratably by year over the life of the contracts. The value of the lease contract is amortized over the term of the lease. See footnote for Page 110, Line 72, Column c. The following reflects the purchase accounting adjustments:

Other Deferred Credits (253) Without Purchase Accounting	$ 6,945,601
Purchase Accounting Adjustment – coal supply contracts	22,605,479
2011 Amortization of purchase accounting adjustment – coal supply contracts	(11,735,750)
2010 Amortization of purchase accounting adjustment – coal supply contracts	(4,728,247)
Purchase Accounting Adjustment – rent commitment	900,950
2011 Amortization of purchase accounting adjustment – rent commitment	(189,673)
2010 Amortization of purchase accounting adjustment – rent commitment	(31,612)
Total for Other Deferred Credits (253)	$ 13,766,748

Schedule Page: 112 Line No.: 59 Column: d

The balance in Other Deferred Credits (253) was adjusted due to the purchase of KU by PPL in November 2010. The adjustments represent the fair value of certain coal supply contracts based upon the difference between estimated market prices of the coal to be purchased and the actual prices in the contracts and the fair value of a lease contract based upon the difference between the estimated market price of the leased property and the actual lease costs. The adjustments were recorded with a regulatory liability offset since the actual costs of these contracts are recoverable through rate mechanisms. The value of the coal contracts is amortized ratably by year over the life of the contracts. The value of the lease contract is amortized over the term of the lease. See footnote for Page 110, Line 72, Column c. The following reflects the purchase accounting adjustments:

Other Deferred Credits (253) Without Purchase Accounting	$ 8,491,443
Purchase Accounting Adjustment – coal supply contracts	22,605,479
Amortization of purchase accounting adjustment – coal supply contracts	(4,728,247)
Purchase Accounting Adjustment – rent commitment	900,950
Amortization of purchase accounting adjustment – rent commitment	(31,612)
Total for Other Deferred Credits (253)	$ 27,238,013

Schedule Page: 112 Line No.: 60 Column: c

The balance in Other Regulatory Liabilities (254) was adjusted to reflect regulatory offsets due to the purchase of KU by PPL in November 2010. The account was adjusted for coal supply contracts, emissions allowances and a power purchase contract. Coal contracts were adjusted to reflect the fair value based upon the difference between estimated market prices of the coal to be purchased and the actual prices in the contracts. Emissions allowances were adjusted to reflect the fair value based upon the difference between the estimated market prices and the actual cost of the allowances. Using the offer of a transaction by another owner as an indication of the fair value, the fair value of the power purchase contract was calculated using a weighted average of the announced offer and the allotted megawatt multiplied by KU's megawatt capacity. The value assigned to the purchase power contract was the difference between KU's original investment and the $39 million for KU.

The balances will be amortized as the underlying purchase accounting adjustments are amortized. See footnote for Page 110, Line 78, Column c. The following reflects the purchase accounting adjustments:

Other Regulatory Liabilities (254) Without Purchase Accounting	$ 108,313,656
Purchase Accounting Adjustment - coal supply contracts	144,919,879
2011 Amortization of Purchase Accounting Adjustment - coal supply contracts	(39,807,234)
2010 Amortization of Purchase Accounting Adjustment – coal supply contracts	(3,338,879)
Purchase Accounting Adjustment - Allowances	9,259,090
2011 Amortization of Purchase Accounting Adjustment - emission allowances	(5,771,743)
2010 Amortization of Purchase Accounting Adjustment - emission allowances	(983,780)
Purchase Accounting Adjustment - power purchase contract	38,582,028
2011 Amortization of Purchase Accounting Adjustment - power purchase contract	(2,432,244)
2010 Amortization of Purchase Accounting Adjustment - power purchase contract	(464,152)
Total for Other Regulatory Liabilities (254)	$ 248,276,621

Schedule Page: 112 Line No.: 60 Column: d

The balance in Other Regulatory Liabilities (254) was adjusted to reflect regulatory offsets due to the purchase of KU by PPL in November 2010. The account was adjusted for coal supply contracts, emissions allowances, and a power purchase contract. Coal contracts were adjusted to reflect the fair value based upon the difference between estimated market prices of the coal to be purchased and the actual prices in the contracts. Emissions allowances were adjusted to reflect the fair value based upon the difference between the estimated market prices and the actual cost of the allowances. Using the offer of a transaction by another owner as an indication of the fair value, the fair value of the power purchase contract was calculated using a weighted average of the announced offer and the allotted megawatt multiplied by KU's megawatt capacity. The value assigned to the purchase power contract was the difference between KU's original investment and the $39 million for KU.

The balances will be amortized as the underlying purchase accounting adjustments are amortized. See footnote for Page 110, Line 78, Column d. The following reflects the purchase accounting adjustments:

Other Regulatory Liabilities (254) Without Purchase Accounting	$ 55,112,630
Purchase Accounting Adjustment - coal supply contracts	144,919,879
Amortization of Purchase Accounting Adjustment - coal supply contracts	(3,338,879)

Purchase Accounting Adjustment - Allowances	9,259,090
Amortization of Purchase Accounting Adjustment - emission allowances	(983,780)
Purchase Accounting Adjustment - power purchase contract	38,582,028
Amortization of Purchase Accounting Adjustment - power purchase contract	(464,152)
Total for Other Regulatory Liabilities (254)	$ 243,086,816

Schedule Page: 112 Line No.: 64 Column: c

The balance in Accumulated Deferred Income Taxes – Other (283) was adjusted due to the purchase of KU by PPL in November 1, 2010. The purchase accounting adjustments were to reflect the deferred income tax impact of purchase accounting adjustments related to emission allowances, certain coal supply contracts and a power purchase contract, and regulatory assets for certain coal contracts and a lease contract as of the acquisition date. The deferred income taxes are amortized as the underlying purchase accounting adjustments are amortized. See footnotes for Page 110, Line 21, Column c; Page 110, Line 72, Column c; and, Page 110, Line 78, Column c. The following reflects the purchase accounting adjustments:

Accumulated Deferred Income Taxes (283) Without Purchase Accounting	$ 63,837,724
Purchase Accounting Adjustment – power purchase contract	15,008,409
2011 Amortization of purchase accounting adjustment – power purchase contract	(946,143)
2010 Amortization of purchase accounting adjustment – power purchase contract	(180,555)
Purchase Accounting Adjustment – emission allowances	3,601,785
2011 Amortization of purchase accounting adjustment – emission allowances	(2,245,208)
2010 Amortization of purchase accounting adjustment – emission allowances	(382,690)
Purchase Accounting Adjustment – coal supply contracts	56,373,833
2011 Amortization of purchase accounting adjustment – coal supply contracts	(15,485,014)
2010 Amortization of purchase accounting adjustment – coal supply contracts	(1,298,823)
Purchase Accounting Adjustment – regulatory asset for coal supply contracts	8,793,531
2011 Amortization of purchase accounting adjustment – regulatory asset for coal supply contracts	(4,565,207)
2010 Amortization of purchase accounting adjustment – regulatory asset for coal supply contracts	(1,839,288)
Purchase Accounting Adjustment – regulatory asset for lease contract	350,470
2011 Amortization of purchase accounting adjustment – lease contract	(86,080)
Purchase Accounting Adjustment – EEI investment	8,161,214
2011 Amortization of purchase accounting adjustment – EEI investment	(344,678)
2010 Amortization of purchase accounting adjustment – EEI investment	(57,448)
Eliminate Deferred Tax on Purchase Accounting Adjustment – Other Comprehensive Income	(1,267,489)
Total for Accumulated Deferred Income Taxes (283)	$ 127,428,343

Schedule Page: 112 Line No.: 64 Column: d

The balance in Accumulated Deferred Income Taxes – Other (283) was adjusted due to the purchase of KU by PPL in November 1, 2010. The purchase

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accounting adjustments were to reflect the deferred income tax impact of purchase accounting adjustments related to emission allowances, certain coal supply contracts and a power purchase contract, and regulatory assets for certain coal contracts and a lease contract as of the acquisition date. The deferred income taxes are amortized as the underlying purchase accounting adjustments are amortized. See footnotes for Page 110, Line 21, Column d; Page 110, Line 72, Column d; and, Page 110, Line 78, Column d. The following reflects the purchase accounting adjustments:

Accumulated Deferred Income Taxes (283) Without Purchase Accounting	$ 49,762,543
Purchase Accounting Adjustment – power purchase contract	15,008,409
Amortization of purchase accounting adjustment – power purchase contract	(180,555)
Purchase Accounting Adjustment – emission allowances	3,601,785
Amortization of purchase accounting adjustment – emission allowances	(382,690)
Purchase Accounting Adjustment – coal supply contracts	56,373,833
Amortization of purchase accounting adjustment – coal supply contracts	(1,298,823)
Purchase Accounting Adjustment – regulatory asset for coal supply contracts	8,793,531
Amortization of purchase accounting adjustment – regulatory asset for coal supply contracts	(1,839,288)
Purchase Accounting Adjustment – regulatory asset for lease contract	350,470
Purchase Accounting Adjustment – EEI investment	8,161,214
Amortization of purchase accounting adjustment – EEI investment	(57,448)
Total for Accumulated Deferred Income Taxes (283)	$ 138,292,981

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,547,516,986	1,511,709,712		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	865,303,893	887,321,741		
5	Maintenance Expenses (402)	320-323	116,303,369	107,813,985		
6	Depreciation Expense (403)	336-337	178,898,265	137,631,388		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	3,028,523	1,650,652		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	7,263,444	6,603,464		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)		5,855,640	5,149,557		
14	Taxes Other Than Income Taxes (408.1)	262-263	28,115,766	19,893,479		
15	Income Taxes - Federal (409.1)	262-263	-6,941,452	61,659,449		
16	- Other (409.1)	262-263	4,455,179	12,756,393		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	277,430,626	227,248,544		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	165,853,891	201,702,906		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		3,293	56,751		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		2,827,117	3,498,905		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,304,971,906	1,259,168,786		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		242,545,080	252,540,926		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,547,516,986	1,511,709,712					2
						3
865,303,893	887,321,741					4
116,303,369	107,813,985					5
178,898,265	137,631,388					6
3,028,523	1,650,652					7
7,263,444	6,603,464					8
						9
						10
						11
						12
5,855,640	5,149,557					13
28,115,766	19,893,479					14
-6,941,452	61,659,449					15
4,455,179	12,756,393					16
277,430,626	227,248,544					17
165,853,891	201,702,906					18
						19
						20
						21
3,293	56,751					22
						23
2,827,117	3,498,905					24
1,304,971,906	1,259,168,786					25
242,545,080	252,540,926					26

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		242,545,080	252,540,926		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		29,710	144,377		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		635	107,737		
33	Revenues From Nonutility Operations (417)		56,169	288,620		
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	1,037,115	3,613,346		
37	Interest and Dividend Income (419)		101,284	118,845		
38	Allowance for Other Funds Used During Construction (419.1)		42,662	521,152		
39	Miscellaneous Nonoperating Income (421)		381,873	-3,347,311		
40	Gain on Disposition of Property (421.1)		78,505	14,885		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		1,726,683	1,246,177		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		1,602			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,054,767	716,135		
46	Life Insurance (426.2)		-1,979,269	-1,887,393		
47	Penalties (426.3)		250,395	3,119		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,114,497	1,145,405		
49	Other Deductions (426.5)		808,004	1,086,637		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,249,996	1,063,903		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	2,004	2,004		
53	Income Taxes-Federal (409.2)	262-263	-921,896	-2,299,144		
54	Income Taxes-Other (409.2)	262-263	-252,272	-413,222		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,212,718	2,972,746		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,082,341	1,511,495		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		2,686,401	71,100		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-4,728,188	-1,320,211		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		5,204,875	1,502,485		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		61,174,245	10,418,088		
63	Amort. of Debt Disc. and Expense (428)		3,123,234	584,124		
64	Amortization of Loss on Reaquired Debt (428.1)		604,973	604,818		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		6,321	64,142,346		
68	Other Interest Expense (431)		5,371,461	3,832,380		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		12,955	968,597		
70	Net Interest Charges (Total of lines 62 thru 69)		70,267,279	78,613,159		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		177,482,676	175,430,252		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		177,482,676	175,430,252		

Schedule Page: 114 Line No.: 2 Column: d

Includes rates subject to refunds of $632,384, which were collected through rates.

Schedule Page: 114 Line No.: 4 Column: c

The balance in Operation Expenses (401) was adjusted due to the purchase of KU by PPL in November 2010. The balance was adjusted to include amortization of the purchase accounting adjustment related to the rent commitment for the Corporate Headquarters building. The rent commitment amortization inadvertently charged to Operation Expense in 2010 was reclassified to Other Regulatory Liabilities (254) in January 2011. The following reflects the purchase accounting adjustment:

Operation Expenses (401) Without Purchase Accounting	$ 865,272,281
Purchase Accounting Adjustment - rent commitment	31,612
Total for Operation Expenses (401)	$ 865,303,893

Schedule Page: 114 Line No.: 4 Column: d

The balance in Operation Expenses (401) was adjusted due to the purchase of KU by PPL in November 2010. The balance was adjusted to include amortization of the purchase accounting adjustment related to the rent commitment for the Corporate Headquarters building. The rent commitment amortization inadvertently charged to Operation Expense in 2010 was reclassified to Other Regulatory Liabilities (254) in January 2011. The following reflects the purchase accounting adjustment:

Operation Expenses (401) Without Purchase Accounting	$ 887,353,353
Purchase Accounting Adjustment - rent commitment	(31,612)
Total for Operation Expenses (401)	$ 887,321,741

Schedule Page: 114 Line No.: 4 Column: g

The balance in Operation Expenses (401) was adjusted due to the purchase of KU by PPL in November 2010. The balance was adjusted to include amortization of the purchase accounting adjustment related to the rent commitment for the Corporate Headquarters building. The rent commitment amortization inadvertently charged to Operation Expense in 2010 was reclassified to Other Regulatory Liabilities (254) in January 2011. The following reflects the purchase accounting adjustment:

Operation Expenses (401) Without Purchase Accounting	$ 865,272,281
Purchase Accounting Adjustment - rent commitment	31,612
Total for Operation Expenses (401)	$ 865,303,893

Schedule Page: 114 Line No.: 4 Column: h

The balance in Operation Expenses (401) was adjusted due to the purchase of KU by PPL in November 2010. The balance was adjusted to include amortization of the purchase accounting adjustment related to the rent commitment for the Corporate Headquarters building. The rent commitment amortization inadvertently charged to Operation Expense in 2010 was reclassified to Other Regulatory Liabilities (254) in January 2011. The following reflects the purchase accounting adjustment:

Operation Expenses (401) Without Purchase Accounting	$ 887,353,353
Purchase Accounting Adjustment - rent commitment	(31,612)
Total for Operation Expenses (401)	$ 887,321,741

Schedule Page: 114 Line No.: 17 Column: c

The balance in Provision for Deferred Income Taxes (410.1) was adjusted due to the purchase of KU by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 250,984,982
Purchase Accounting Adjustment - coal contract	22,215,026
Purchase Accounting Adjustment - emission allowance	2,487,623
Purchase Accounting Adjustment - pensions	561,594
Purchase Accounting Adjustment - pollution control bonds	27,185
Purchase Accounting Adjustment - post retirement	23,318
Purchase Accounting Adjustment - OVEC	1,048,297
Purchase Accounting Adjustment - rent commitment	82,413
Purchase Accounting Adjustment - other	188
Total for Provision for Deferred Income Taxes (410.1)	$ 277,430,626

Schedule Page: 114 Line No.: 17 Column: d

The balance in Provision for Deferred Income Taxes (410.1) was adjusted due to the purchase of KU by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 227,227,951
Purchase Accounting Adjustment - EEI Investments	3,101
Purchase Accounting Adjustment - pollution control bonds	4,531
Purchase Accounting Adjustment - rent commitment	12,961
Total for Provision for Deferred Income Taxes (410.1)	$ 227,248,544

Schedule Page: 114 Line No.: 17 Column: g

The balance in Provision for Deferred Income Taxes (410.1) was adjusted due to the purchase of KU by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 250,984,982
Purchase Accounting Adjustment - coal contract	22,215,026
Purchase Accounting Adjustment - emission allowance	2,487,623
Purchase Accounting Adjustment - pensions	561,594
Purchase Accounting Adjustment - pollution control bonds	27,185
Purchase Accounting Adjustment - post retirement	23,318
Purchase Accounting Adjustment - OVEC	1,048,297
Purchase Accounting Adjustment - rent commitment	82,413
Purchase Accounting Adjustment - other	188
Total for Provision for Deferred Income Taxes (410.1)	$ 277,430,626

Schedule Page: 114 Line No.: 17 Column: h

The balance in Provision for Deferred Income Taxes (410.1) was adjusted due to the purchase of KU by PPL Corporation in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 227,227,951
Purchase Accounting Adjustment - EEI Investments	3,101
Purchase Accounting Adjustment - pollution control bonds	4,531
Purchase Accounting Adjustment - rent commitment	12,961
Total for Provision for Deferred Income Taxes (410.1)	$ 227,248,544

Schedule Page: 114 Line No.: 18 Column: c

The balance in Provision for Deferred Income Taxes (411.1) was adjusted due to the purchase of KU by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 139,421,743
Purchase Accounting Adjustment - coal contract	22,215,026
Purchase Accounting Adjustment - emission allowance	2,487,623
Purchase Accounting Adjustment - pensions	561,594
Purchase Accounting Adjustment - pollution control bonds	1,392
Purchase Accounting Adjustment - post retirement	23,318
Purchase Accounting Adjustment - OVEC	1,048,297
Purchase Accounting Adjustment - rent commitment	94,710
Purchase Accounting Adjustment - other	188
Total for Provision for Deferred Income Taxes (411.1)	$ 165,853,891

Schedule Page: 114 Line No.: 18 Column: d

The balance in Provision for Deferred Income Taxes (411.1) was adjusted due to the purchase of KU by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 201,641,461
Purchase Accounting Adjustment - EEI Investments	60,549
Purchase Accounting Adjustment - pollution control bonds	232
Purchase Accounting Adjustment - rent commitment	664
Total for Provision for Deferred Income Taxes (411.1)	$ 201,702,906

Schedule Page: 114 Line No.: 18 Column: g

The balance in Provision for Deferred Income Taxes (411.1) was adjusted due to the purchase of KU by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 139,421,743
Purchase Accounting Adjustment - coal contract	22,215,026
Purchase Accounting Adjustment - emission allowance	2,487,623
Purchase Accounting Adjustment - pensions	561,594
Purchase Accounting Adjustment - pollution control bonds	1,392
Purchase Accounting Adjustment - post retirement	23,318
Purchase Accounting Adjustment - OVEC	1,048,297
Purchase Accounting Adjustment - rent commitment	94,710
Purchase Accounting Adjustment - other	188
Total for Provision for Deferred Income Taxes (411.1)	$ 165,853,891

Schedule Page: 114 Line No.: 18 Column: h

The balance in Provision for Deferred Income Taxes (411.1) was adjusted due to the purchase of KU by PPL Corporation in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 201,641,461
Purchase Accounting Adjustment - EEI Investments	60,549
Purchase Accounting Adjustment - pollution control bonds	232
Purchase Accounting Adjustment - rent commitment	664
Total for Provision for Deferred Income Taxes (411.1)	$ 201,702,906

Schedule Page: 114 Line No.: 36 Column: c

The balance in Equity in Earnings of Subsidiary Companies (418.1) was adjusted due to the purchase of KU by PPL in November 2010. The balance was adjusted to include amortization of the purchase accounting adjustment related to the investment in EEI. The following reflects the purchase accounting adjustment:

Equity in Earnings of Subsidiary Companies (418.1) Without Purchase Accounting	$	1,923,199
Purchase Accounting Adjustment - EEI Investment		(886,084)
Total for Equity in Earnings of Subsidiary Companies (418.1)	$	1,037,115

Schedule Page: 114 Line No.: 36 Column: d

The balance in Equity in Earnings of Subsidiary Companies (418.1) was adjusted due to the purchase of KU by PPL in November 2010. The balance was adjusted to include amortization of the purchase accounting adjustment related to the investment in EEI. The following reflects the purchase accounting adjustment:

Equity in Earnings of Subsidiary Companies (418.1) Without Purchase Accounting	$	3,761,027
Purchase Accounting Adjustment - EEI Investment		(147,681)
Total for Equity in Earnings of Subsidiary Companies (418.1)	$	3,613,346

Schedule Page: 114 Line No.: 39 Column: d

The balance includes depreciation expense of $3,634,336 related to plant held for future use.

Schedule Page: 114 Line No.: 46 Column: c

The balance includes the increase in the cash surrender value less the monthly premium amounts that are paid from the cash surrender value balance.

Schedule Page: 114 Line No.: 46 Column: d

The balance includes the increase in the cash surrender value less the monthly premium amounts that are paid from the cash surrender value balance.

Schedule Page: 114 Line No.: 55 Column: c

The balance in Provision for Deferred Income Taxes (410.2) was adjusted due to the purchase of KU by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.2) Without Purchase Accounting	$	1,125,686
Purchase Accounting Adjustment – EEI investment		87,032
Total for Provision for Deferred Income Taxes (410.2)	$	1,212,718

Schedule Page: 114 Line No.: 56 Column: c

The balance in Provision for Deferred Income Taxes (411.2) was adjusted due to the purchase of KU by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (411.2) Without Purchase Accounting	$	383,142
Purchase Accounting Adjustment – EEI investment		1,699,199
Total for Provision for Deferred Income Taxes (411.2)	$	2,082,341

Schedule Page: 114 Line No.: 62 Column: c

The balance in Interest on Long-Term Debt (427) was adjusted due to the purchase of KU by PPL in November 2010. The balance was adjusted to include amortization of the fair value adjustment related to the fixed rate pollution control bonds. The following reflects the purchase accounting adjustment:

Interest on Long-Term Debt (427) Without Purchase Accounting	$	61,240,551
Amortization of Purchase Accounting Adjustment -		

pollution control bonds	(66,306)
Total for Interest on Long-Term Debt (427)	$ 61,174,245

Schedule Page: 114 Line No.: 62 Column: d

The balance in Interest on Long-Term Debt (427) was adjusted due to the purchase of KU by PPL in November 2010. The balance was adjusted to include amortization of the fair value adjustment related to the fixed rate pollution control bonds. The following reflects the purchase accounting adjustment:

Interest on Long-Term Debt (427) Without Purchase Accounting	$ 10,429,139
Amortization of Purchase Accounting Adjustment - pollution control bonds	(11,051)
Total for Interest on Long-Term Debt (427)	$ 10,418,088

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		35,351,542	1,317,618,203
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Purchase Accounting Adjustment			(1,404,083,567)
11	Rounding		1	
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		1	(1,404,083,567)
16	Balance Transferred from Income (Account 433 less Account 418.1)		176,445,561	171,816,906
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Without Par Value		-123,500,000	(50,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-123,500,000	(50,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		88,297,104	35,351,542
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		88,297,104	35,351,542
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		43,895	10,671,369
50	Equity in Earnings for Year (Credit) (Account 418.1)		1,037,115	3,613,346
51	(Less) Dividends Received (Debit)			
52	Purchase Accounting Adjustment			(14,240,820)
53	Balance-End of Year (Total lines 49 thru 52)		1,081,010	43,895

Schedule Page: 118 Line No.: 10 Column: d

The balance was adjusted due to the purchase of KU by PPL in November 2010. The adjustment eliminated Retained Earnings at October 31, 2010.

Schedule Page: 118 Line No.: 38 Column: c

The balance in Retained Earnings (215, 215.1, 216) was adjusted due to the purchase of KU by PPL in November 2010. The adjustment eliminated Retained Earnings at October 31, 2010 and included amortization of purchase accounting adjustments recorded as of the acquisition date. See footnotes for Page 112, Line 7, Column c; Page 114, Line 4, Column c; Page 114, Line 17, Column c; Page 114, Line 18, Column c; Page 114, Line 36, Column c and Page 114, Line 62, Column c. The following reflects the purchase accounting adjustment:

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$ 1,490,663,791
Elimination of Retained Earnings	(1,404,083,567)
2011 Amortization of Purchase Accounting Adjustment – rent commitment (net of deferred taxes of $(12,297))	(19,315)
2010 Amortization of Purchase Accounting Adjustment – rent commitment (net of deferred taxes of $12,297)	19,315
2011 Amortization of Purchase Accounting Adjustment – pollution control bonds (net of deferred taxes of $25,793)	40,513
2010 Amortization of Purchase Accounting Adjustment – pollution control bonds (net of deferred taxes of $4,299)	6,752
2011 Deferred Tax on Amortization of Purchase Accounting Adjustment – EEI investment (see Line 53 Column c footnote for related Purchase Accounting Adjustment)	344,678
2010 Deferred Tax on Amortization of Purchase Accounting Adjustment – EEI investment (see Line 53 Column c footnote for related Purchase Accounting Adjustment)	57,448
Eliminate Deferred Tax on Purchase Accounting Adjustment – Other Comprehensive Income	1,267,489
Total for Retained Earnings (215, 215.1, 216)	$ 88,297,104

Schedule Page: 118 Line No.: 38 Column: d

The balance in Retained Earnings (215, 215.1, 216) was adjusted due to the purchase of KU by PPL in November 2010. The adjustment eliminated Retained Earnings at October 31, 2010 and included amortization of purchase accounting adjustments recorded as of the acquisition date. See footnotes for Page 112, Line 7, Column d. The following reflects the purchase accounting adjustment:

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$ 1,439,351,594
Elimination of Retained Earnings	(1,404,083,567)
2010 Amortization of Purchase Accounting Adjustment – rent commitment (net of deferred taxes of $12,297)	19,315
2010 Amortization of Purchase Accounting Adjustment – pollution control bonds (net of deferred taxes of $4,299)	6,752
2010 Deferred Tax on Amortization of Purchase Accounting Adjustment – EEI investment (see Line 53 Column d footnote for related Purchase Accounting Adjustment)	57,448
Total for Retained Earnings (215, 215.1, 216)	$ 35,351,542

Schedule Page: 118 Line No.: 50 Column: c

The Unappropriated Undistributed Subsidiary Earnings (216.1) was adjusted for ($886,084) included in Equity in Earnings for Year (418.1) due to the purchase of KU by PPL in November 2010. This adjustment represents twelve months of the amortization of KU's purchase accounting adjustment related to KU's investment in Electric Energy, Inc.:

Equity in Earnings for Year (418.1)		
Without Purchase Accounting	$	1,923,199
Amortization of Purchase Accounting Adjustment		(886,084)
Equity in Earnings for Year (418.1)	$	1,037,115

Schedule Page: 118 Line No.: 50 Column: d

The Unappropriated Undistributed Subsidiary Earnings (216.1) was adjusted for ($147,681) included in Equity in Earnings for Year (418.1) due to the purchase of KU by PPL in November 2010. This adjustment represents two months of the amortization of KU's purchase accounting adjustment related to KU's investment in Electric Energy, Inc.:

Equity in Earnings for Year (418.1)		
Without Purchase Accounting	$	3,761,027
Amortization of Purchase Accounting Adjustment		(147,681)
Equity in Earnings for Year (418.1)	$	3,613,346

Schedule Page: 118 Line No.: 52 Column: d

The balance was adjusted due to the purchase of KU by PPL in November 2010. The adjustment eliminated Undistributed Subsidiary Earnings at October 31, 2010.

Schedule Page: 118 Line No.: 53 Column: c

The balance in Unappropriated Undistributed Subidiary Earnings (216.1) was adjusted for Equity in Earnings for year (418.1) due to the purchase of KU by PPL in November 2010. This adjustment represents the amortization of KU's purchase accounting adjustment related to KU's investment in EEI:

Unappropriated Undistributed Subsidary Earnings (216.1)		
Without Purchase Accounting	$	16,355,595
Purchase Accounting Adjustment		(14,240,820)
2011 Amortization of Purchase Accounting Adjustment (see Line 38 Column c footnote for related deferred tax)		(886,084)
2010 Amortization of Purchase Accounting Adjustment (see Line 38 Column c footnote for related deferred tax)		(147,681)
Total for Undistributed Subsidary Earnings (216.1)	$	1,081,010

Schedule Page: 118 Line No.: 53 Column: d

The balance in Unappropriated Undistributed Subidiary Earnings (216.1) was adjusted for Equity in Earnings for year (418.1) due to the purchase of KU by PPL in November 2010. This adjustment represents the amortization of KU's purchase accounting adjustment related to KU's investment in Electric Energy, Inc:

Unappropriated Undistributed Subsidary Earnings (216.1)		
Without Purchase Accounting	$	14,432,396
Purchase Accounting Adjustment		(14,240,820)
2010 Amortization of Purchase Accounting Adjustment (see Line 38 Column d footnote for related deferred tax)		(147,681)
Total for Undistributed Subsidary Earnings (216.1)	$	43,895

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	177,482,676	175,430,252
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	181,926,788	139,282,040
5	Amortization of Plant	7,263,444	6,603,464
6			
7			
8	Deferred Income Taxes (Net)	110,548,505	28,662,845
9	Investment Tax Credit Adjustment (Net)	-2,615,303	
10	Net (Increase) Decrease in Receivables	35,883,200	-12,131,506
11	Net (Increase) Decrease in Inventory	-3,808,082	-618,958
12	Net (Increase) Decrease in Allowances Inventory	116,117	408,497
13	Net Increase (Decrease) in Payables and Accrued Expenses	-23,441,083	5,802,573
14	Net (Increase) Decrease in Other Regulatory Assets	-53,358,837	45,268,394
15	Net Increase (Decrease) in Other Regulatory Liabilities	53,342,425	10,868,189
16	(Less) Allowance for Other Funds Used During Construction	29,707	1,489,749
17	(Less) Undistributed Earnings from Subsidiary Companies	1,923,199	3,761,027
18	Other (provide details in footnote):	-43,771,829	-18,411,812
19	Change in other deferred debits	39,843	-2,358,473
20	Change in other deferred credits	-1,344,903	-1,458,452
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	436,310,055	372,096,277
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-258,840,832	-428,563,722
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-29,707	-1,489,749
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-258,811,125	-427,073,973
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	92,810	-4,381
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	-12,930,503	-55,328
54	Change in restricted cash	-45,500	
55	Change in Non-Hedging Derivatives		17,947
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-271,694,318	-427,115,735
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	-2,875,370	1,472,221,502
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	-2,875,370	1,472,221,502
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-1,298,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)	-10,434,000	-67,540,954
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-123,500,000	-50,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-136,809,370	56,680,548
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	27,806,367	1,661,090
87			
88	Cash and Cash Equivalents at Beginning of Period	3,333,447	1,672,357
89			
90	Cash and Cash Equivalents at End of period	31,139,814	3,333,447

Schedule Page: 120 Line No.: 18 Column: b

Other operating cash flows:

Depreciation charged to balance sheet accounts	$ (43,966,084)
Accumulated Provision for Uncollectible Accounts - Credit	(5,886,136)
Other changes in Net Utility Plant	39,224,309
Amortization of Debt Expenses and Losses on Bonds	3,093,073
Unamortized Discount on Long-Term Debt - Debit	635,250
Net increase in Prepayments and other assets	(7,101,062)
Net decrease in Preliminary Survey	675,183
Net increase in Other Comprehensive Income	(464,223)
Net increases in Customer Advances for Construction	286,665
Net increase in Asset Retirement Obligations	7,808,276
Net increase in the Provision for Pension and Postretirement Benefits	12,173,020
Pension and Postretirement Funding	(50,044,299)
Net increase in Change in Non-Hedging Derivatives	210,779
Gains and Losses on Interest Rate Swaps	208,723
Net increase in Other Liabilities	(259,968)
Gains on Disposals of Assets	(74,124)
Proceeds received on the sale of assets	(303,707)
Investment in subsidiary and other investments	759,776
Change in Deferred Income Taxes - purchase accounting	13,496
Change in Unappropriated Undistributed Subsidiary Earnings - purchase accounting	(726,082)
Change in Debt - purchase accounting	(66,306)
Change in Other Regulatory Assets - purchase accounting	31,612
Total	$ (43,771,829)

Schedule Page: 120 Line No.: 18 Column: c

Other operating cash flows:

Depreciation charged to balance sheet accounts	$ (36,909,643)
Other changes in Net Utility Plant	(1,916,116)
Amortization of Debt Expenses and Losses on Bonds	1,188,942
Net decrease in Prepayments and other current assets	19,193
Net decrease in Preliminary Survey	977,236
Net decrease in Other Comprehensive Income	(1,993,677)
Net decrease in Customer Advances for Construction	(58,648)
Net increase in Asset Retirement Obligations	10,095,490
Net increase in the Provision for Pension and Postretirement Benefits	27,106,897
Pension and Postretirement Funding	(20,373,490)
Net increase in Change in Non-Hedging Derivatives	65,279
Gains and Losses on Interest Rate Swaps	59,587
Gains on Disposals of Assets	10,504
Proceeds received on the sale of assets	(10,504)
Investment in subsidiary and other investments	3,262,974
Change in Deferred Income Taxes - purchase accounting	(40,852)
Change in Unappropriated Undistributed Subsidiary Earnings - purchase accounting	147,681
Change in Long-Term Debt - purchase accounting	(11,051)
Change in Miscellaneous Long-Term Liabilities - purchase accounting	(31,612)
Rounding	(2)
Total	$ (18,411,812)

Schedule Page: 120 Line No.: 53 Column: b

Other investing cash flows:

Costs incurred related to Asset Retirement Obligations	$	(12,930,503)

Schedule Page: 120 Line No.: 53 Column: c

Other investing cash flows:

Costs incurred related to Asset Retirement Obligations	$	(55,328)

Schedule Page: 120 Line No.: 90 Column: b

Cash and cash equivalents is comprised of the following amounts:

Cash (131)	$	31,096,140
Temporary Cash Investments (136)		43,674

Total Cash and Cash Equivalents at the End of Period	$	31,139,814

Schedule Page: 120 Line No.: 90 Column: c

Cash and cash equivalents is comprised of the following amounts:

Cash (131)	$	3,132,600
Temporary Cash Investments (136)		200,847

Total Cash and Cash Equivalents at the End of Period	$	3,333,447

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

GLOSSARY OF TERMS AND ABBREVIATIONS

KU **-** Kentucky Utilities Company, a public utility subsidiary of LKE engaged in the regulated generation, transmission, distribution and sale of electricity, primarily in Kentucky. The subsidiary was acquired by PPL through the acquisition of LKE in November 2010.

LG&E **-** Louisville Gas and Electric Company, a public utility affiliate of KU and subsidiary of LKE engaged in the regulated generation, transmission, distribution and sale of electricity and the distribution and sale of natural gas in Kentucky. The subsidiary was acquired by PPL through the acquisition of LKE in November 2010.

LKE **-** LG&E and KU Energy LLC (formerly E.ON U.S. LLC), a subsidiary of PPL and the parent of KU, LG&E and other subsidiaries. PPL acquired E.ON U.S. LLC in November 2010 and changed the name to LG&E and KU Energy LLC. Within the context of this document, references to LKE also relate to the consolidated entity.

LKS **-** LG&E and KU Services Company, a subsidiary of LKE that provides services for LKE and its subsidiaries. The subsidiary was acquired by PPL through the acquisition of LKE in November 2010.

PPL **-** PPL Corporation, the parent holding company of PPL Electric, PPL Energy Funding, LKE and other subsidiaries.

PPL Energy Supply **-** PPL Energy Supply, LLC, an affiliate of KU, subsidiary of PPL Energy Funding and the parent company of PPL Generation, PPL EnergyPlus and other subsidiaries.

Other terms and abbreviations

2011 Registration Statement **-** refers to the registration statement on Form S-4 filed with the SEC by KU (Registration No. 333-173675) on April 22, 2011, as amended by Amendment No. 1 filed with the SEC on May 26, 2011 and effective June 1, 2011.

Acid Rain Program **-** allowance trading system established by the Clean Air Act to reduce levels of sulfur dioxide. Under this program, affected power plants are allocated allowances based on their fuel consumption during specified baseline years and a specific emissions rate.

AFUDC **-** Allowance for Funds Used During Construction. The cost of equity and debt funds used to finance construction projects of regulated businesses, which is capitalized as part of construction costs.

AOCI **-** accumulated other comprehensive income or loss.

ARO **-** asset retirement obligation.

Bluegrass CTs **-** Three natural gas combustion turbines owned by Bluegrass Generation. KU and LG&E entered into an Asset Purchase Agreement with Bluegrass Generation for the purchase of these combustion turbines, subject to certain conditions including receipt of applicable regulatory approvals and clearances.

Bluegrass Generation **-** Bluegrass Generation Company, L.L.C., an exempt wholesale electricity generator in LaGrange, Kentucky.

CAIR **-** the EPA's Clean Air Interstate Rule.

Clean Air Act **-** federal legislation enacted to address certain environmental issues related to air emissions, including acid rain, ozone and toxic air emissions.

CPCN **-** Certificate of Public Convenience and Necessity. Authority granted by the KPSC pursuant to Kentucky Revised Statute 278.020 to provide utility service to or for the public or the construction of any plant, equipment, property or facility for furnishing of utility service to the public.

CSAPR **-** Cross-State Air Pollution Rule, the CSAPR implements Clean Air Act requirements concerning the transport of air pollution from power plants across state boundaries. The CSAPR replaces the 2005 CAIR, which the U.S. Court of Appeals for the D.C. Circuit ordered the EPA to revise in 2008. The court has granted a stay allowing CAIR to remain in place pending a ruling on the legal challenges to the CSAPR.

Dodd-Frank Act **-** the Dodd-Frank Wall Street Reform and Consumer Protection Act that was signed into law in July 2010.

DOE **-** Department of Energy, a U.S. government agency.

DSM **-** Demand Side Management. Pursuant to Kentucky Revised Statute 278.285, the KPSC may determine the reasonableness of DSM plans proposed by any utility under its jurisdiction. Proposed DSM mechanisms may seek full recovery of DSM programs and revenues lost by implementing those programs and/or incentives designed to provide financial rewards to the utility for implementing cost-effective DSM programs. The cost of such programs shall be assigned only to the class or classes of customers which benefit from the programs.

ECR **-** Environmental Cost Recovery. Pursuant to Kentucky Revised Statute 278.183, effective January 1993, Kentucky electric utilities are entitled to the current recovery of costs of complying with the Clean Air Act, as amended, and those federal, state or local environmental requirements which apply to coal combustion and by-products from the production of energy from coal.

EEI **-** Electric Energy, Inc., which owns and operates a coal-fired plant and a natural gas facility in southern Illinois.

EMF **-** electric and magnetic fields.

E.ON AG **-** a German corporation and the indirect parent of E.ON US Investments Corp., the former parent of LKE.

EPA **-** Environmental Protection Agency, a U.S. government agency.

FERC **-** Federal Energy Regulatory Commission, the federal agency that regulates, among other things, interstate transmission and wholesale sales of electricity, hydroelectric power projects and related matters.

GAAP **-** Generally Accepted Accounting Principles in the U.S.

GHG - greenhouse gas(es).

Health Care Reform - The Patient Protection and Affordable Care Act (HR 3590) and the Health Care and Education Reconciliation Act of 2010 (HR 4872), signed into law in March 2010.

IRP **-** Integrated Resource Plan. Pursuant to Kentucky Administrative Regulation 807 5:058, Kentucky electric utilities are required to file triennially an IRP with the KPSC. The filing is to provide the utilities' load forecasts and resource plans to meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers while satisfying all related state and federal laws and regulations.

***IRS* -** Internal Revenue Service, a U.S. government agency.

***ISO* -** Independent System Operator.

***KPSC* -** Kentucky Public Service Commission, the state agency that has jurisdiction over the regulation of rates and service of utilities in Kentucky.

***KU 2010 Mortgage Indenture* -** KU's Indenture dated as of October 1, 2010, to The Bank of New York Mellon, as trustee, as supplemented.

***kWh* -** kilowatt-hour, basic unit of electrical energy.

***LIBOR* -** London Interbank Offered Rate.

***MATS* -** Mercury and Air Toxics Standards.

***MW* -** megawatt, one thousand kilowatts.

***MWh* -** megawatt-hour, one thousand kilowatt-hours.

***NERC* -** North American Electric Reliability Corporation.

***NGCC* -** Natural gas-fired combined-cycle turbine.

***NPDES* -** National Pollutant Discharge Elimination System.

***NPNS* -** the normal purchases and normal sales exception as permitted by derivative accounting rules. Derivatives that qualify for this exception receive accrual accounting treatment.

***OCI* -** other comprehensive income or loss.

***Opacity* -** The degree to which emissions reduce the transmission of light and obscure the view of an object in the background. There are emission regulations that limit the opacity in power plant stack gas emissions.

***OVEC* -** Ohio Valley Electric Corporation, located in Piketon, Ohio, an entity in which LKE indirectly owns an 8.13% interest (consists of LG&E's 5.63% and KU's 2.50% interests), which is accounted for as a cost-method investment. OVEC owns and operates two coal-fired power plants, the Kyger Creek Plant in Ohio and the Clifty Creek Plant in Indiana, with combined nameplate capacities of 2,390 MW.

***PP&E* -** property, plant and equipment.

***Predecessor* -** refers to the KU pre-acquisition activity covering the time period prior to November 1, 2010.

***S&P* -** Standard & Poor's Ratings Services, a credit rating agency.

***SCR* -** selective catalytic reduction, a pollution control process for the removal of nitrogen oxide from exhaust gases.

Scrubber **-** an air pollution control device that can remove particulates and/or gases (such as sulfur dioxide) from exhaust gases.

SEC **-** the U.S. Securities and Exchange Commission, a U.S. government agency whose primary mission is to protect investors and maintain the integrity of the securities markets.

Securities Act of 1933 **-** the Securities Act of 1933, 15 U.S. Code, Sections 77a-77aa, as amended.

Successor **-** refers to the KU post-acquisition activity covering the time period after October 31, 2010.

Superfund **-** federal environmental legislation that addresses remediation of contaminated sites; states also have similar statutes.

TC2 **-** Trimble County Unit 2, a coal-fired plant located in Kentucky with a net summer capacity of 732 MW. LKE indirectly owns a 75% interest (consists of LG&E's 14.25% and KU's 60.75% interests) in TC2, or 549 MW of the capacity.

TRA **-** Tennessee Regulatory Authority, the state agency that has jurisdiction over the regulation of rates and service of utilities in Tennessee.

VaR **-** value-at-risk, a statistical model that attempts to estimate the value of potential loss over a given holding period under normal market conditions at a given confidence level.

VIE **-** variable interest entity.

VSCC **-** Virginia State Corporation Commission, the state agency that has jurisdiction over the regulation of Virginia corporations, including utilities.

As permitted by the FERC for the Year Ended December 31, 2011 Form 1, the Notes to Financial Statements set forth below are principally from the Respondent's SEC Form 10-K for the Year Ended December 31, 2011, which was filed with the SEC on February 28, 2012. Accordingly, these Notes do not reflect updated information since this filing date.

NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

General

Capitalized terms and abbreviations are explained in the glossary. Dollars are in millions unless otherwise noted.

Presentation

The accompanying financial statements are prepared on the regulatory basis of accounting in accordance with the requirements of the FERC, which is a comprehensive basis of accounting other than GAAP. The significant differences between GAAP and FERC reporting are as follows:

(a) Certain cost of removal obligations are recorded in accumulated depreciation for FERC reporting and recorded in regulatory liabilities for GAAP reporting;
(b) Long-term and short-term bonds are recorded in total in the long-term debt section for FERC reporting and are presented separately in current liabilities for the short-term portion and in long-term debt for the long-term portion for GAAP reporting;
(c) Deferred taxes are shown gross for FERC reporting in the Balance Sheet (a deferred asset and a deferred liability are recorded), for GAAP reporting the deferred taxes are netted together and recorded as a net asset or net liability; and
(d) Utility Plant is stated at cost for FERC reporting and at net fair value for assets recorded at November 1, 2010 for GAAP reporting.

Business and Consolidation

KU is engaged in the regulated generation, transmission, distribution and sale of electricity. KU serves its customers in Virginia under the Old Dominion Power name.

The financial statements and accompanying footnotes of KU have been segregated to present pre-acquisition activity as the "Predecessor" and post-acquisition activity as the "Successor." Predecessor activity covers the time period prior to November 1, 2010. Successor activity covers the time period after October 31, 2010. Certain accounting and presentation methods were changed to acceptable alternatives in the Successor financial statements to conform to PPL's accounting policies. The cost basis of certain assets and liabilities were changed as of November 1, 2010 as a result of the application of push-down accounting. Consequently, the financial position, results of operations and cash flows for the Successor period are not comparable to the Predecessor period. "Earnings reinvested" on the Balance Sheet of KU was reset to $0 as of November 1, 2010 and only reflects earnings and dividend activity since that date. See Note 5 for information about an application filed with the FERC regarding future dividend payments related to this push-down accounting impact.

The financial statements of KU include the company's own accounts as well as the accounts of any entities in which the company has a controlling financial interest. Entities for which a controlling financial interest is not demonstrated through voting interests are evaluated based on accounting guidance for VIEs. KU consolidates a VIE when it is determined to have a controlling interest in the VIE, and thus is the primary beneficiary of the entity. KU has no controlling interest in a VIE. Investments in entities in which a company has the ability to exercise significant influence but does not have a controlling financial interest are accounted for under the equity method. All other investments are carried at cost or fair value. All significant intercompany transactions have been eliminated. Any noncontrolling interests are reflected in the financial statements.

The financial statements of KU include its share of any undivided interests in jointly owned facilities, as well as its share of the related operating costs of those facilities. See Note 10 for additional information.

Regulation

KU is a cost-based rate-regulated utility for which rates are set by regulators to enable KU to recover the costs of providing electric service and to provide a reasonable return to shareholders. Rates are generally established based on a historical test period adjusted to exclude unusual or nonrecurring items. As a result, the financial statements are subject to the accounting for certain types of regulation as prescribed by GAAP and reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery of underlying costs is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise currently be charged to expense. Regulatory liabilities are recognized for amounts expected to be returned through future regulated customer rates. In certain cases, regulatory liabilities are recorded based on an understanding or agreement with the regulator that rates have been set to recover costs that are expected to be incurred in the future, and the regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC or the applicable state regulatory commissions. See Note 4 for additional details regarding regulatory matters.

Accounting Records

The system of accounts is maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the applicable state regulatory commissions.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Loss Accruals

Potential losses are accrued when (1) information is available that indicates it is "probable" that a loss has been incurred, given the likelihood of the uncertain future events and (2) the amount of the loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." KU continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events. Loss accruals are discounted when appropriate.

The accrual of contingencies that might result in gains is not recorded, unless recovery is assured.

Changes in Classification

The classification of certain amounts in the 2010 financial statements have been changed to conform to the current presentation. The changes in classification did not affect KU's net income or equity.

Comprehensive Income

Comprehensive income, which includes net income and OCI, consists of changes in equity from transactions not related to shareowners. Comprehensive income is shown on the Statements of Comprehensive Income.

KU had no AOCI balances at December 31, 2010 and 2011 (Successor periods). KU had $2 million of after-tax losses related to equity investees' AOCI during the ten months ended October 31, 2010 (a Predecessor period) which were eliminated with the effect of the PPL acquisition.

Price Risk Management

Energy and energy-related contracts are used to hedge the variability of expected cash flows associated with the generating units and marketing activities. Similar derivatives may receive different accounting treatment, depending on management's intended use and documentation.

All contracts that have been classified as derivative contracts are reflected on the balance sheet at their fair value. These contracts are recorded as "Price risk management assets" and "Price risk management liabilities" on the Balance Sheets. Derivative positions that deliver within a year are included in "Current Assets" and "Current Liabilities," while derivative positions that deliver beyond a year are recorded in "Other Noncurrent Assets" and "Deferred Credits and Other Noncurrent Liabilities."

Energy and energy-related trades are assigned a strategy and accounting classification. Processes exist that allow for subsequent review and validation of the trade information. These strategies are discussed in more detail in Note 15. The accounting department provides the traders and the risk management department with guidelines on appropriate accounting classifications for various trade types and strategies. Some examples of these guidelines include, but are not limited to:

- Physical coal, limestone, lime, electric transmission, gas transportation and renewable energy credit contracts are not derivatives due to the lack of net settlement provisions.

- Only contracts where physical delivery is deemed probable throughout the entire term of the contract can qualify for the NPNS exception.
- Derivative transactions that do not qualify for NPNS or hedge accounting treatment are marked to fair value through earnings.

Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing activities on the Statements of Cash Flows, depending on the underlying nature of the hedged items.

KU has elected not to offset net derivative positions against the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

See Notes 14 and 15 for additional information on derivatives.

Revenue Recognition

Operating revenues are recorded based on energy deliveries through the end of the calendar month. Unbilled retail revenues result because customers' meters are read and bills are rendered throughout the month, rather than all being read at the end of the month. Unbilled revenues for a month are calculated by multiplying an estimate of unbilled kWh by the estimated average cents per kWh. Unbilled wholesale energy revenues are recorded at month-end to reflect estimated amounts until actual dollars and MWhs are confirmed and invoiced. At that time, unbilled revenue is reversed and actual revenue is recorded.

Accounts Receivable

Accounts receivable are reported on the Balance Sheets at the gross outstanding amount adjusted for an allowance for doubtful accounts. Accounts receivable that are acquired are initially recorded at fair value on the date of acquisition. See Note 7 for information related to the acquisition of LKE by PPL.

Allowance for Doubtful Accounts

Accounts receivable collectability is evaluated using a combination of factors, including past due status based on contractual terms, trends in write-offs, the age of the receivable, counterparty creditworthiness and economic conditions. Specific events, such as bankruptcies, are also considered. Adjustments to the allowance for doubtful accounts are made when necessary based on the results of analysis, the aging of receivables, and historical and industry trends.

Accounts receivable are written off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable previously written off are recorded when it is known they will be received.

The changes in the allowance for doubtful accounts were:

	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
2011 - Successor	$ 6	$ 6	$ -	$ 10	$ 2
2010 - Successor	-	1	6	1	6
2010 - Predecessor	3	6	-	6	3

(a) Primarily related to capital projects, thus the provision was recorded as an adjustment to construction work in progress.
(b) Includes amounts associated with KU activity since the November 1, 2010 acquisition date. See Note 7 for additional information related to the acquisition of LKE.

Cash

Cash Equivalents

All highly liquid debt instruments purchased with original maturities of three months or less are considered to be cash equivalents.

Restricted Cash and Cash Equivalents

Bank deposits and other cash equivalents that are restricted by agreement or that have been clearly designated for a specific purpose are classified as restricted cash and cash equivalents. The change in restricted cash and cash equivalents is reported as an investing activity on the Statements of Cash Flows. On the Balance Sheets, the current portion of restricted cash and cash equivalents is included in "Other current assets" for KU while the noncurrent portion is included in "Other noncurrent assets." At December 31 the balances of restricted cash and cash equivalents were insignificant.

Fair Value Measurements

KU values certain financial and nonfinancial assets and liabilities at fair value. Generally, the most significant fair value measurements relate to price risk management assets and liabilities, investments in securities including investments in defined benefit plans, and cash and cash equivalents. KU uses, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques and option-pricing models) and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

KU classifies fair value measurements within one of three levels in the fair value hierarchy. The level assigned to a fair value measurement is based on the lowest level input that is significant to the fair value measurement in its entirety. The three levels of the fair value hierarchy are as follows:

- **Level 1** - quoted prices (unadjusted) in active markets for identical assets or liabilities that are accessible at the measurement date. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.
- **Level 2** - inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for substantially the full term of the asset or liability.
- **Level 3** - unobservable inputs that management believes are predicated on the assumptions market participants would use to measure the asset or liability at fair value.

Assessing the significance of a particular input requires judgment that considers factors specific to the asset or liability. As such, KU's assessment of the significance of a particular input may affect how the assets and liabilities are classified within the fair value hierarchy.

Investments

Generally, the original maturity date of an investment and management's intent and ability to sell an investment prior to its original maturity determine the classification of investments as either short-term or long-term. Investments that would otherwise be classified as short-term, but are restricted as to withdrawal or use for other than current operations or are clearly designated for expenditure in the acquisition or construction of noncurrent assets or for the liquidation of long-term debts, are classified as long-term.

Short-term Investments

Short-term investments generally include certain deposits as well as securities that are considered highly liquid or provide for periodic reset of interest rates. Investments with original maturities greater than three months and less than a year, as well as investments with original maturities of greater than a year that management has the ability and intent to sell within a year, are included in "Short-term investments" ("Other current assets" if not material) on the Balance Sheets.

Equity Method Investment

KU's investment in EEI is included in "Investments" on the Balance Sheets. KU owns 20% of the common stock of EEI. Through a power marketer affiliated with its majority owner, EEI sells its output to third parties. KU's investment in EEI is accounted for under the equity method of accounting and amounted to $30 million at December 31, 2011 and 2010. As part of PPL's acquisition of LKE and its subsidiaries, the purchase accounting adjustment to reflect the EEI investment at fair value was calculated using the discounted cash flow valuation method. The fair value of the investment in EEI was calculated to be $30 million. The fair value adjustment to the investment is being amortized over the expected remaining useful life of the plant and equipment at EEI, which is estimated to be over 20 years. KU's direct exposure to loss as a result of its involvement with EEI is generally limited to the value of its investment.

Cost Method Investment

KU has an investment in OVEC, which is accounted for using the cost method. The investment is recorded in "Investments" on the KU Balance Sheet. KU and 11 other electric utilities are equity owners of OVEC, located in Piketon, Ohio. OVEC owns and operates two coal-fired plants, Kyger Creek Plant in Ohio and Clifty Creek Plant in Indiana, with combined nameplate generating capacities of 2,390 MW. OVEC's power is currently supplied to KU and 12 other companies affiliated with the various owners. KU owns 2.5% of OVEC's common stock. Pursuant to a power purchase agreement, KU is contractually entitled to its ownership percentage of OVEC's output, which is 60 MW.

KU's investment in OVEC is not significant. The direct exposure to loss as a result of KU's involvement with OVEC is generally limited to the value of its investment; however, KU may be conditionally responsible for a pro-rata share of certain OVEC obligations. As part of PPL's acquisition of LKE, the value of the power purchase contract was recorded as an intangible asset with the offset to a regulatory liability which are both being amortized using the units-of-production method until March 2026, the expiration date of the agreement at the date of the acquisition. See Notes 11 and 16 for additional discussion on the power purchase agreement.

Long-Lived and Intangible Assets

Property, Plant and Equipment

PP&E is recorded at original cost, unless impaired. If impaired, the asset is written down to fair value at that time, which becomes the new cost basis of the asset. Original cost includes material, labor, contractor costs, certain overheads and financing costs, where applicable. The cost of repairs and minor replacements are charged to expense as incurred. KU records costs associated with planned major maintenance projects in the period in which the costs are incurred. KU accrues costs of removal net of estimated salvage value through depreciation, which is included in the calculation of customer rates over the assets' depreciable lives in accordance with regulatory practices. Cost of removal amounts accrued through depreciation rates are accumulated as a regulatory liability until the removal costs are incurred. See Note 4 for additional information.

AFUDC is capitalized as part of the construction costs for cost-based rate-regulated projects for which a return on such costs is recovered after the project is placed in service. The debt component of AFUDC is credited to "Interest Expense" and the equity component is credited to "Other Income (Expense) - net" on the Statements of Income. KU has not recorded significant AFUDC as a return has been provided during the construction period for most projects.

Included in PP&E on the Balance Sheets are capitalized costs of software projects that were developed or obtained for internal use. These capitalized costs are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Following are capitalized software costs and the accumulated amortization.

December 31, 2011		December 31, 2010	
Gross Carrying Amount	**Accumulated Amortization**	**Gross Carrying Amount**	**Accumulated Amortization**
$ 49	$ 8	$ 40	$ 1

Amortization expense of capitalized software costs was as follows:

Successor		Predecessor
Year Ended December 31, 2011	**Two Months Ended December 31, 2010**	**Ten Months Ended October 31, 2010**
$ 7	$ 1	$ 6

The amortization of capitalized software is included in "Depreciation" on the Statements of Income.

Depreciation

Depreciation is recorded over the estimated useful lives of property using various methods including the straight-line, composite and group methods. When a component of PP&E that was depreciated under the composite or group method is retired, the original cost is charged to accumulated depreciation. When all or a significant portion of an operating unit that was depreciated under the composite or group method is retired or sold, the property and the related accumulated depreciation account is reduced and any gain or loss is included in income, unless otherwise required by regulators. The weighted-average rates of depreciation were 4.17% and 4.10% at December 31, 2011 and 2010.

As a result of the acquisition of LKE, the original cost for PP&E is its fair value on November 1, 2010, which approximated net book value. This fair value adjustment resulted in lowering the original cost basis of KU's PP&E, thus impacting the calculation of the weighted-average depreciation rate.

Goodwill and Other Intangible Assets

Goodwill represents the excess of the purchase price paid over the fair value of the identifiable net assets acquired in a business combination.

Other acquired intangible assets are initially measured based on their fair value. Intangibles that have finite useful lives are amortized over their useful lives based upon the pattern in which the economic benefits of the intangible assets are consumed or otherwise used. Costs incurred to renew or extend terms of licenses are capitalized as intangible assets.

When determining the useful life of an intangible asset, including intangible assets that are renewed or extended, KU considers the expected use of the asset; the expected useful life of other assets to which the useful life of the intangible asset may relate; legal, regulatory, or contractual provisions that may limit the useful life; the company's historical experience as evidence of its ability to support renewal or extension; the effects of obsolescence, demand, competition, and other economic factors; and the level of maintenance expenditures required to obtain the expected future cash flows from the asset.

KU accounts for emission allowances as intangible assets. KU is allocated emission allowances by state based on its generation facilities' historical emissions experience, and has purchased emission allowances generally when it is expected that additional allowances will be needed. The carrying value of allocated emission allowances is initially recorded at zero value and purchased allowances are initially recorded based on their purchase price. KU emission allowances acquired in the LKE acquisition were recorded at fair value on the date of acquisition. See Note 7 for additional information on the acquisition. When consumed or sold, emission allowances are removed from the Balance Sheet at their weighted-average carrying value. Since the economic benefits of emission allowances are not diminished until they are consumed, emission allowances are not amortized; rather, they are expensed when consumed or a gain or loss is recognized when sold. Such expense is included in "Fuel" on the Statements of Income. Gains and losses on the sale of emission allowances are included in "Other operation and maintenance" on the Statements of Income.

Asset Impairment

KU reviews long-lived assets that are subject to depreciation or amortization, including finite-lived intangibles, for impairment when events or circumstances indicate carrying amounts may not be recoverable. For example, certain emission allowances are expected to be sold rather than consumed. These emission allowances are tested for impairment when events or changes in circumstances, such as a decline in market prices, indicate that their carrying value may not be recoverable.

A long-lived asset classified as held and used is impaired when the carrying amount of the asset exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If impaired, the asset's carrying value is written down to its fair value.

A long-lived asset classified as held for sale is impaired when the carrying amount of the asset (disposal group) exceeds its fair value less cost to sell. If impaired, the asset's (disposal group's) carrying value is written down to its fair value less cost to sell.

Goodwill is reviewed for impairment at the reporting unit level annually or more frequently when events or circumstances indicate that the carrying amount of a reporting unit may be greater than the unit's fair value. Additionally, goodwill must be tested for impairment after a portion of goodwill has been allocated to a business to be disposed of. If the carrying amount of KU, including goodwill, exceeds its fair value, the implied fair value of goodwill must be calculated in the same manner as goodwill in a business combination. The fair value of a reporting unit is allocated to all assets and liabilities of that unit as if the reporting unit had been acquired in a business combination. The excess of the fair value of the reporting unit over the amounts assigned to its assets and liabilities is the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, goodwill is written down to its implied fair value.

Asset Retirement Obligations

KU records liabilities to reflect various legal obligations associated with the retirement of long-lived assets. Initially, this obligation is measured at fair value and offset with an increase in the value of the capitalized asset, which is depreciated over the asset's useful life. Until the obligation is settled, the liability is increased to reflect changes in the obligation due to the passage of time through the recognition of accretion expense classified within "Other operation and maintenance" on the Statements of Income. The accretion and depreciation related to KU's AROs are offset with a regulatory credit on the income statement, such that there is no earnings impact. The regulatory asset created by the regulatory credit is relieved when the ARO is settled.

Estimated ARO costs and settlement dates, which affect the carrying value of the ARO and the related capitalized asset, are reviewed periodically to ensure that any material changes are incorporated into the latest estimate of the ARO. Any change to the capitalized asset, positive or negative, is amortized over the remaining life of the associated long-lived asset. See Note 17 for additional information on AROs.

Compensation and Benefits

Defined Benefits

KU does not directly sponsor any defined benefit plans. KU participates in a qualified funded defined benefit pension and a funded other postretirement benefit plan. These plans are applicable to the majority of the employees of KU and are sponsored by LKE. LKE allocates a portion of the liability and net periodic defined benefit pension and other postretirement costs of the plans to KU based on its participation. KU records an asset or liability to recognize the funded status of all defined benefit plans with an offsetting entry to regulatory assets or liabilities. Consequently, the funded status of all defined benefit plans is fully recognized on the Balance Sheets.

The expected return on plan assets is determined based on a market-related value of plan assets, which is calculated by rolling forward the prior year market-related value with contributions, disbursements and long-term expected return on investments. One-fifth of the difference between the actual value and the expected value is added (or subtracted if negative) to the expected value to determine the new market-related value.

LKE uses an accelerated amortization method for the recognition of gains and losses for its defined benefit pension plans. Under the accelerated method, actuarial gains and losses in excess of 30% of the plan’s projected benefit obligation are amortized on a straight-line basis over one-half of the expected average remaining service of active plan participants. Actuarial gains and losses in excess of 10% of the greater of the plan’s projected benefit obligation or the market-related value of plan assets and less than 30% of the plan’s projected benefit obligation are amortized on a straight-line basis over the expected average remaining service period of active plan participants.

See Note 9 for a discussion of defined benefits.

Other

Debt Issuance Costs

Debt issuance costs are deferred and amortized over the appropriate term for the related debt using the interest method or another method, generally straight-line, if the results obtained are not materially different than those that would result from the interest method.

Income Taxes

KU is included in PPL's consolidated U.S. federal income tax return. Prior to PPL's acquisition of LKE, KU was included in E.ON US Investments Corp.'s consolidated U.S. federal income tax return.

Significant management judgment is required in developing KU's provision for income taxes, primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and the determination of deferred tax assets, liabilities and valuation allowances.

Significant management judgment is also required to determine the amount of benefit to be recognized in relation to an uncertain tax position. KU uses a two-step process to evaluate tax positions. The first step requires an entity to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires an entity to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact the financial statements of KU in the future.

Deferred income taxes reflect the net future tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes, as well as the tax effects of net operating losses and tax credit carryforwards.

KU records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. KU considers the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies in initially recording and subsequently reevaluating the need for valuation allowances. If KU determines that it is able to realize deferred tax assets in the future in excess of recorded net deferred tax assets, adjustments to the valuation allowances increase income by reducing tax expense in the period that such determination is made. Likewise, if KU determines that it is not able to realize all or part of net deferred tax assets in the future, adjustments to the valuation allowances would decrease income by increasing tax expense in the period that such determination is made.

KU defers investment tax credits when the credits are utilized and amortizes the deferred amounts over the average lives of the related assets.

KU recognizes interest and penalties in "Income Taxes" on the Statements of Income.

See Note 3 for additional discussion regarding income taxes.

The income tax provision for KU is calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if KU filed a separate return. Tax benefits are not shared between companies. A tax benefit inures only to the entity that gave rise to said benefit. The effect of PPL filing a consolidated tax return is taken into account in the settlement of current taxes and the recognition of deferred taxes. KU's intercompany tax receivable was $5 million at December 31, 2011 and the intercompany tax payable was $15 million at December 31, 2010.

The provision for KU's deferred income taxes for regulated assets is based upon the ratemaking principles reflected in rates established by the regulators. The difference in the provision for deferred income taxes for regulated assets and the amount that otherwise would be recorded under GAAP is deferred and included on the Balance Sheet in noncurrent "Regulatory assets" or "Regulatory liabilities."

Taxes, Other Than Income

KU presents sales taxes in "Accounts Payable" and value-added taxes in "Taxes" on its Balance Sheet. These taxes are not reflected on the Statements of Income. See Note 3 for details on taxes included in "Taxes, other than income" on the Statements of Income.

Leases

KU evaluates whether arrangements entered into contain leases for accounting purposes. See Note 8 for a discussion of arrangements under which KU is a lessee for accounting purposes.

Fuel, Materials and Supplies

Fuel and materials and supplies are valued at the lower of cost or market using the average cost method. Fuel costs for electric generation are charged to expense as used. See Note 4 for further discussion of the fuel adjustment clause.

"Fuel, materials and supplies" on the Balance Sheets consisted of the following at December 31.

	2011	2010
Fuel	$ 97	$ 95
Materials and supplies	44	41
Total	$ 141	$ 136

Guarantees

Generally, the initial measurement of a guarantee liability is the fair value of the guarantee at its inception. However, there are certain guarantees excluded from the scope of accounting guidance and other guarantees that are not subject to the initial recognition and measurement provisions of accounting guidance that only require disclosure. See Note 11 for further discussion of recorded and unrecorded guarantees.

New Accounting Guidance Adopted

Presentation of Comprehensive Income

Effective December 31, 2011, KU retrospectively adopted accounting guidance that was issued to improve the comparability, consistency and transparency of financial reporting and to increase the prominence of items that are recorded in OCI. This guidance requires that all non-owner changes in stockholders' equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements where the first statement includes the components of net income and the second statement includes the components of OCI.

Regardless of whether an entity chooses to present comprehensive income in a single continuous statement or in two separate but consecutive statements, the guidance also would have required an entity to present on the face of the financial statements reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement(s) where the components of net income and the components of other comprehensive income are presented. However, subsequent to the issuance of this new accounting guidance, this requirement that companies present reclassification adjustments for each component of OCI in both net income and OCI on the face of the financial statements was deferred for further evaluation. The deferral did not change the requirement to present items of net income, items of other comprehensive income and total comprehensive income in either one continuous statement or two separate consecutive statements.

KU has elected to present two separate consecutive statements of comprehensive income. The adoption of this standard resulted in a change in presentation and additional footnote disclosure that did not have a significant impact on KU.

2. Preferred Securities

Preferred Stock

KU is authorized to issue up to 5,300,000 shares of preferred stock without par value. KU had no preferred stock issued or outstanding in 2011 or 2010.

Preference Stock

KU is authorized to issue up to 2,000,000 shares of preference stock without par value. KU had no preference stock issued or outstanding in 2011 or 2010.

3. Income and Other Taxes

The provision for KU's deferred income taxes for regulated assets is based upon the ratemaking principles reflected in rates established by the KPSC, VSCC, TRA and the FERC. The difference in the provision for deferred income taxes for regulated assets and the amount that otherwise would be recorded under GAAP is deferred and included in "Regulatory liabilities" on the Balance Sheets.

Significant components of KU's deferred income tax assets and liabilities were as follows:

	2011	2010
Deferred Tax Assets		
Regulatory liabilities and other	$ 58	$ 92
Deferred investment tax credit (a)	39	1
Income taxes due to customers	7	5
Accrued pension costs	9	9
Liabilities and other	6	6
Total deferred tax assets	119	113
Deferred Tax Liabilities		
Plant - net	500	350
Regulatory assets and other	98	133
Total deferred tax liabilities	598	483
Net deferred tax liability	$ 479	$ 370

(a) Changes in balance primarily relate to investment tax credits for TC2, which began dispatching electricity in January 2011. See discussion on TC2 below.

KU expects to have adequate levels of taxable income to realize its recorded deferred income tax assets.

Details of the components of income tax expense, a reconciliation of federal income taxes derived from statutory tax rates applied to "Income Before Income Taxes" to income taxes for reporting purposes, and details of "Taxes, other than income" were:

	Successor			
	Year Ended December 31, 2011		Two Months Ended December 31, 2010	
Income Tax Expense (Benefit)				
Current - Federal	$	(8)	$	13
Current - State		4		3
Total Current Expense		(4)		16
Deferred - Federal		101		4
Deferred - State		10		-
Total Deferred Expense		111		4
Investment tax credit, net - Federal		(3)		-
Total income tax expense (a)	$	104	$	20
Total income tax expense - Federal	$	90	$	17
Total income tax expense - State		14		3
Total income tax expense (a)	$	104	$	20

	Predecessor	
	Ten Months Ended October 31, 2010	
Income Tax Expense (Benefit)		
Current - Federal	$	46
Current - State		9
Total Current Expense		55
Deferred - Federal		20
Deferred - State		3
Total Deferred Expense		23
Investment tax credit, net - Federal		-
Total income tax expense (a)	$	78
Total income tax expense - Federal	$	66
Total income tax expense - State		12
Total income tax expense (a)	$	78

(a) Excludes deferred federal and state tax (benefit) recorded to OCI of $(1) million for the ten month period ended October 31, 2010. Also excludes deferred federal and state tax expense (benefit) recorded to Regulatory assets of $(1) million in 2011, $1 million for the two month period ended December 31, 2010 and $2 million for the ten month period ended October 31, 2010.

	Predecessor
	Ten Months Ended October 31, 2010
Reconciliation of Income Taxes	
Federal income tax on Income Before Income Taxes at statutory tax rate - 35%	$ 77
Increase (decrease) due to:	
State income taxes, net of federal income tax benefit	8
Other	(7)
Total increase (decrease)	1
Total income tax expense	$ 78
Effective income tax rate	35.8%

	Successor	
	Year Ended December 31, 2011	Two Months Ended December 31, 2010
Reconciliation of Income Taxes		
Federal income tax on Income Before Income Taxes at statutory tax rate - 35%	$ 99	$ 19
Increase (decrease) due to:		
State income taxes, net of federal income tax benefit	9	2
Other	(4)	(1)
Total increase (decrease)	5	1
Total income tax expense	$ 104	$ 20
Effective income tax rate	36.9%	36.4%

	Successor		Predecessor
	Year Ended December 31, 2011	Two Months Ended December 31, 2010	Ten Months Ended October 31, 2010
Taxes, other than income			
Property and other	$ 19	$ 1	$ 9

In June 2006, KU and LG&E filed a joint application with the DOE requesting certification to be eligible for $125 million in investment tax credits ($101 million to KU and $24 million to LG&E) applicable to the construction of TC2. All necessary DOE and IRS approvals were subsequently received. In September 2007, KU and LG&E received an Order from the KPSC approving the accounting of the investment tax credits, which includes full depreciation basis adjustment for the amount of the credits. The income tax impacts from recording the depreciation basis adjustment and from amortizing these credits over the life of the related property began in January 2011, when LKE began dispatching electricity from TC2 to meet customer demand. In 2011, $2 million of net tax benefits were recognized for KU and LG&E.

Unrecognized Tax Benefits

KU's unrecognized tax benefits and changes in those unrecognized tax benefits are insignificant at December 31, 2011 and 2010. For KU, no significant changes in unrecognized tax benefits are projected over the next 12 months. At December 31, the total unrecognized tax benefits and related indirect effects that, if recognized, would decrease the effective tax rate were insignificant for KU.

At December 31, 2011 and 2010, the receivable (payable) balances were recorded for interest related to tax positions. The amounts for KU were insignificant. The interest expense (benefit) was recognized in income taxes. The amount for KU was insignificant.

Tax Jurisdictions

The income tax provisions for KU are calculated in accordance with an intercompany tax sharing policy which provides that taxable income be calculated as if each subsidiary filed a separate consolidated return. KU indirectly or directly files tax returns in two major tax jurisdictions. With few exceptions, at December 31, 2011, these jurisdictions, as well as the tax years that are no longer subject to examination, were as follows:

U.S. (federal) (a)	10/31/2010 and prior
Kentucky (state)	2006 and prior

(a) For KU, 2008 and 2009, as well as the ten month period ending October 31, 2010, remain open under the standard three year statute of limitations; however, the IRS has completed its audit of these periods under the Compliance Assurance Process, effectively closing them to audit adjustments. No issues remain outstanding.

4. Utility Rate Regulation

As discussed in Note 1 and summarized below, KU reflects the effects of regulatory actions in the financial statements for its cost-based rate-regulated utility operations. Regulatory assets and liabilities are classified as current if, upon initial recognition, the entire amount related to that item will be recovered or refunded within a year of the balance sheet date. As such, the primary items classified as current are related to rate mechanisms that periodically adjust to account for over- or under-collections.

KU is subject to the jurisdiction of the KPSC, FERC, VSCC and TRA.

KU’s Kentucky base rates are calculated based on a return on capitalization (common equity, long-term debt and notes payable) including certain adjustments to exclude non-regulated investments and environmental compliance costs recovered separately through the ECR mechanism. As such, regulatory assets generally earn a return.

As a result of purchase accounting requirements, certain fair value amounts related to contracts that had favorable or unfavorable terms relative to market were recorded on the Balance Sheets with an offsetting regulatory asset or liability. KU recovers in customer rates the cost of coal contracts, power purchases and emission allowances. As a result, management believes the regulatory assets and liabilities created to offset the fair value amounts at the acquisition date meet the recognition criteria established by existing accounting guidance and eliminate any rate making impact of the fair value adjustments. KU's customer rates will continue to reflect the original contracted prices for these contracts.

KU's Virginia base rates are calculated based on a return on rate base (net utility plant plus working capital less deferred taxes and miscellaneous deductions). All regulatory assets and liabilities, except the levelized fuel factor, are excluded from the return on rate base utilized in the calculation of Virginia base rates; therefore, no return is earned on the related assets.

KU's rates to municipal customers for wholesale requirements are calculated based on annual updates to a rate formula that utilizes a return on rate base (net utility plant plus working capital less deferred taxes and miscellaneous deductions). All regulatory assets and liabilities are excluded from the return on rate base utilized in the development of municipal rates; therefore, no return is earned on the related assets.

The following tables provide information about the regulatory assets and liabilities of cost-based rate-regulated utility operations.

	2011	2010
Current Regulatory Assets:		
Coal contracts (a)	$ -	$ 4
Virginia fuel factor	-	5
Total current regulatory assets	$ -	$ 9
Noncurrent Regulatory Assets:		
Defined benefit plans	$ 114	$ 117
Storm costs	57	57
Unamortized loss on debt	12	12
Coal contracts (a)	6	14
AROs	7	2
Other	21	19
Total noncurrent regulatory assets	$ 217	$ 221
Current Regulatory Liabilities:		
Coal contracts (a)	$ -	$ 15
ECR	7	12
Other	3	13
Total current regulatory liabilities	$ 10	$ 40
Noncurrent Regulatory Liabilities:		
Coal contracts (a)	$ 102	$ 126
Power purchase agreement - OVEC (a)	36	38
Net deferred tax assets	8	6
Defined benefit plans	9	10
Other	5	6
Total noncurrent regulatory liabilities	$ 160	$ 186

(a) These regulatory assets and liabilities were recorded as offsets to certain intangible assets and liabilities that were recorded at fair value upon the acquisition of LKE.

Regulatory Assets and Liabilities

Following is an overview of selected regulatory assets and liabilities detailed in the preceding tables. Specific developments with respect to certain of these regulatory assets and liabilities are discussed in "Regulatory Matters."

Defined Benefit Plans

Recoverable costs of defined benefit plans represent the portion of unrecognized transition obligation, prior service cost and net actuarial losses that will be recovered in defined benefit plans expense through future base rates based upon established regulatory practices. These regulatory assets and liabilities are adjusted at least annually or whenever the funded status of defined benefit plans is re-measured. Of the regulatory asset and liability balances recorded, $10 million are expected to be amortized into net periodic defined benefit costs in 2012. All costs will be amortized over the average service lives of plan participants.

Storm Costs

KU has the ability to request from the KPSC and VSCC the authority to treat expenses related to specific extraordinary storms as a regulatory asset and defer and amortize such costs for regulatory accounting and reporting purposes. Once such authority is granted, KU can request recovery of those expenses in a base rate case.

Unamortized Loss on Debt

Unamortized loss on reacquired debt represents losses on long-term debt reacquired or redeemed that have been deferred and will be amortized and recovered over either the original life of the extinguished debt or the life of the replacement debt (in the case of refinancing). Such costs are being amortized through 2036 for KU.

ECR

Kentucky law permits KU to recover the costs, including a return of operating expenses and a return of and on capital invested, of complying with the Federal Clean Air Act and those federal, state or local environmental requirements which apply to coal combustion wastes and by-products from coal-fired electric generating facilities. The KPSC requires reviews of the past operations of the environmental surcharge for six-month and two-year billing periods to evaluate the related charges, credits and rates of return, as well as to provide for the roll-in of ECR amounts to base rates each two-year period. The ECR regulatory asset or liability represents the amount that has been under- or over-recovered due to timing or adjustments to the mechanism and is recovered within 12 months. KU is authorized to receive a 10.63% return on equity for the 2005, 2006 and 2009 compliance plans and a 10.10% return on projects associated with the 2011 compliance plan.

Coal Contracts

As a result of purchase accounting associated with PPL's acquisition of LKE, KU's coal contracts were recorded at fair value on the Balance Sheets with offsets to regulatory assets for those contracts with unfavorable terms relative to current market prices and offsets to regulatory liabilities for those contracts with favorable terms relative to current market prices. These regulatory assets and liabilities are being amortized over the same terms as the related contracts, which expire at various times through 2016.

Fuel Adjustments

KU's retail rates contain a fuel adjustment clause, whereby variances in the cost of fuel for electric generation, including transportation costs, from the costs embedded in base rates are adjusted in KU's rates. The KPSC requires public hearings at six-month intervals to examine past fuel adjustments and at two-year intervals to review past operations of the fuel clause and, to the extent appropriate, reestablish the fuel charge included in base rates.

KU also employs a levelized fuel factor mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The Virginia levelized fuel factor allows fuel recovery based on projected fuel costs for the coming year plus an adjustment for any under- or over-recovery of fuel expenses from the prior year. The regulatory assets or liabilities represent the amounts that have been under- or over-recovered due to timing or adjustments to the mechanism and are recovered within 12 months.

AROs

As noted in Note 1, the accretion and depreciation related to KU's AROs are offset with a regulatory credit on the income statement, such that there is no earnings impact. When an asset with an ARO is retired, the related ARO regulatory asset created by the regulatory credit is offset against the associated regulatory liability, PP&E and ARO liability.

DSM

DSM consists of energy efficiency programs which are intended to reduce peak demand and delay the investment in additional power plant construction, provide customers with tools and information to become better managers of their energy usage and prepare for potential future legislation governing energy efficiency. KU's rates contain a DSM rate mechanism that provides for concurrent recovery of DSM costs and also provides an incentive for implementing DSM programs. The provision also allows KU to recover revenues from lost sales associated with the DSM programs up to the earlier of three years or implementation of new base rates which reflect that load reduction. In addition, with the KPSC Order issued in November 2011, the DSM mechanism now includes a provision to earn a return of and on capital investment for DSM programs. The regulatory assets or liabilities represent the total amounts that have been under- or over-recovered due to timing or adjustments to the mechanism.

Power Purchase Agreement - OVEC

As a result of purchase accounting associated with PPL's acquisition of LKE, KU's fair value of the OVEC power purchase agreement was recorded on the balance sheet with an offset to a regulatory liability. The regulatory liability is being amortized using the units-of-production method until March 2026, the expiration date of the agreement at the date of the acquisition, and has no impact on rate making.

Regulatory Liability Associated with Net Deferred Tax Assets

KU's regulatory liabilities associated with net deferred tax assets represent the future revenue impact from the reversal of deferred income taxes required primarily for unamortized investment tax credits. These regulatory liabilities are recognized when the offsetting deferred tax assets are recognized. For general-purpose financial reporting, these regulatory liabilities and the deferred tax assets are not offset; rather, each is displayed separately.

Regulatory Matters

Kentucky Activities

Environmental Upgrades

In order to achieve compliance with new and pending federal EPA regulations including the CSAPR, National Ambient Air Quality Standards and MATS, in June 2011, KU filed an ECR plan with the KPSC requesting approval to install environmental upgrades for certain of its coal-fired plants and for recovery of the associated capital costs, as well as operating expenses incurred. The ECR plan detailed upgrades that will be made to certain of its coal-fired generating plants to continue to be compliant with EPA regulations. KU requested $1.1 billion to upgrade fabric-filter baghouse systems for increased particulate and mercury control on all units at the E.W. Brown and Ghent generating plants and to convert a wet storage facility to a dry landfill at the E.W. Brown generating plant.

In November 2011, KU and LG&E filed a joint unanimous settlement agreement, stipulation and recommendation with the KPSC. In December 2011, KU and LG&E received KPSC approval in their proceedings relating to the ECR plans. The KPSC Order approved the terms of the November 2011 settlement agreement entered into between KU and LG&E and the parties to the ECR proceedings. The KPSC Order authorized the installation of environmental upgrades at certain plants during 2012-2016 representing approximate capital costs of $900 million at KU and $1.4 billion at LG&E. In connection with the approved projects, the KPSC Order allowed recovery through the ECR rate mechanism of the capital costs and operating expenses of the projects and granted CPCNs for their construction. The KPSC Order also confirmed an existing 10.63% authorized return on equity for projects remaining from earlier ECR plans and provided for an authorized return on equity of 10.10% for the approved projects in the 2011 ECR proceedings. The KPSC Order noted KU's consent to defer the requested approval for certain environmental upgrades at its E.W. Brown generating plant, which represented approximately $200 million in capital costs. KU retained the right to operate and dispatch the E.W. Brown generating plant in accordance with applicable environmental standards and the right to request approval of the deferred projects and related costs in future regulatory proceedings. See Note 11 for additional information.

IRP

IRP regulations in Kentucky require major utilities to make triennial IRP filings with the KPSC. In April 2011, KU and LG&E filed their 2011 joint IRP with the KPSC. The IRP provides historical and projected demand, resource and financial data, and other operating performance and system information. In May 2011, the KPSC issued a procedural schedule and data discovery concluded during the fourth quarter. The IRP assumes approximately 500 MW of peak demand reductions by 2017 through existing or expanded DSM or energy efficiency programs. Implementation of the major findings of the IRP is subject to further analysis and decision-making and further regulatory approvals. KU and LG&E are awaiting the KPSC Staff report, which will close this proceeding.

CPCN Filing

In September 2011, KU and LG&E filed a CPCN with the KPSC requesting approval to build a 640 MW NGCC at the existing Cane Run plant site. KU will own a 78% undivided interest, and LG&E will own a 22% undivided interest in the new NGCC. In addition, KU and LG&E also requested approval to purchase the Bluegrass CTs which are expected to provide up to 495 MW of peak generation supply. KU will own a 31% undivided interest, and LG&E will own a 69% undivided interest in the purchased assets. In conjunction with these developments, at the end of 2015, KU anticipates retiring one coal-fired generating unit at its Tyrone plant and two at its Green River plant. These generating units represent 234 MW of combined summer capacity.

KU anticipates that the NGCC construction and the acquisition of the Bluegrass CTs could require up to $500 million in capital costs including related transmission projects. Formal requests for recovery of the costs associated with the NGCC construction and the acquisition of the Bluegrass CTs were not included in the CPCN filing with the KPSC but are expected to be included in future rate proceedings. The KPSC issued an Order on the procedural schedule in the CPCN filing that has discovery scheduled through early February 2012. A KPSC order on the CPCN filing is anticipated in the second quarter of 2012.

PPL's Acquisition of LKE

In September 2010, the KPSC approved a settlement agreement among PPL and all of the intervening parties to PPL's joint application to the KPSC for approval of its acquisition of ownership and control of LKE, LG&E and KU. In the settlement agreement, the parties agreed that KU and LG&E would commit that no base rate increases would take effect before January 1, 2013. Under the terms of the settlement, KU and LG&E retain the right to seek KPSC approval for the deferral of "extraordinary and uncontrollable costs," such as significant storm restoration costs, if incurred. Additionally, interim rate adjustments will continue to be permissible during that period for existing recovery mechanisms such as the ECR and DSM.

In connection with the approval of PPL's acquisition of LKE, KU and LG&E agreed to implement the Acquisition Savings Sharing Deferral (ASSD) methodology whereby KU’s and LG&E's adjusted jurisdictional revenues, expenses, and net operating income are calculated each year. If KU’s or LG&E's actual earned rate of return on common equity is in excess of 10.75%, fifty percent of the excess amount will be deferred as a regulatory liability and ultimately returned to customers. The first ASSD filing will be made by April 1, 2012 based on the 2011 calendar year. Based upon 2011 earnings and their current estimates of the outcome of an ASSD filing in 2012, KU and LG&E have not recognized any impact of the ASSD in the financial statements as of December 31, 2011. The ASSD methodology for each of KU’s and LG&E's utility operations will terminate on the earlier of the end of 2015 or the first day of the calendar year during which new base rates go into effect.

Independent Transmission Operators

KU operates under a FERC-approved open access transmission tariff. KU contracts with the Tennessee Valley Authority, to act as its transmission reliability coordinator, and Southwest Power Pool, Inc. (SPP), to function as its independent transmission operator, pursuant to FERC requirements. The contract with SPP expires on August 31, 2012. KU has received FERC approval to transfer from SPP to TranServ International, Inc. as its independent transmission operator beginning September 1, 2012. Approval from the KPSC is required, and an application requesting approval was filed in January 2012.

Storm Costs

In September 2009, the KPSC approved the deferral of $57 million of costs associated with a severe ice storm that occurred in January 2009 and a wind storm that occurred in February 2009. Additionally, in December 2008, the KPSC approved the deferral of $2 million of costs associated with high winds from the remnants of Hurricane Ike in September 2008. KU received approval in its 2010 base rate case to recover these regulatory assets over a ten-year amortization period ending July 2020.

DSM/Energy Efficiency

In April 2011, KU filed a DSM application to expand existing energy efficiency programs and implement new energy efficiency programs. Discovery and evidentiary phases concluded in September 2011. In November 2011, the KPSC approved the application as filed. The new rates were effective December 30, 2011.

<u>Virginia Activities</u>

IRP

Pursuant to a December 2008 Order, KU filed the 2011 joint IRP with the VSCC in September 2011, with certain supplemental information as required by this Order. The IRP provides historical and projected demand, resource and financial data, and other operating performance and system information and assumes approximately 500 MW of peak demand reductions by 2017 through existing or expanded DSM or energy efficiency programs. Implementation of the major findings of the IRP is subject to further analysis and decision-making and further regulatory approvals.

Virginia Fuel Factor

In February 2011, KU filed an application with the VSCC seeking approval of an increase in its fuel cost factor beginning with service rendered in April 2011. In March 2011, a hearing was held on KU's requested fuel factor, and an Order was issued approving a revised fuel factor to be in effect beginning with service rendered on and after April 1, 2011, with recovery of the regulatory asset for prior period under-recoveries over a three-year amortization period.

Storm Costs

In December 2009, a major snowstorm hit KU's Virginia service area causing approximately 30,000 customer outages. During the normal 2009 Virginia Annual Information Filing (AIF), KU requested that the VSCC establish a regulatory asset and defer for future recovery $6 million in incremental operation and maintenance expenses related to the storm restoration. In March 2011, the VSCC Staff issued its report on KU's 2009 AIF stating that it considered this storm damage to be extraordinary, non-recurring and material to KU. The Staff report also recommended establishing a regulatory asset for these costs, with recovery over a five-year period upon approval in the next base rate case. In March 2011, a regulatory asset of $6 million was established for actual costs incurred. In June 2011, the VSCC issued an Order approving the recommendations contained in the Staff report, and KU began recovering these costs over a five-year amortization period ending October 2016.

5. Financing Activities

Credit Arrangements and Short-term Debt

Credit facilities are maintained to enhance liquidity and provide credit support, and as a backstop to commercial paper programs, when necessary. The following credit facilities were in place at:

	December 31, 2011				
	Expiration Date	Capacity	Borrowed (a)	Letters of Credit Issued	Unused Capacity
Syndicated Credit Facility (b) (c)	Oct. 2016	$ 400	$ -	$ -	$ 400
Letter of Credit Facility (c) (d)	Apr. 2014	198	n/a	198	-
Total KU Credit Facilities		$ 598	$ -	$ 198	$ 400

	December 31, 2010	
	Borrowed (a)	Letters of Credit Issued
Syndicated Credit Facility (b) (c)	$ -	$ 198
Letter of Credit Facility (c) (d)	n/a	n/a
Total KU Credit Facilities	$ -	$ 198

(a) Amounts borrowed are recorded as "Short-term debt" on the Balance Sheets.

(b) In October 2011, KU amended its credit facility. The amendments include extending the expiration dates from December 2014 to October 2016. Under this credit facility, KU continues to have the ability to make cash borrowings and request the lenders to issue letters of credit.

(c) In June 2011, the Syndicated Credit Facility was amended such that the fees and the spreads to benchmark interest rates for borrowings depended upon the company's senior secured long-term debt rating rather than the senior unsecured long-term debt rating. The facilities each contain a financial covenant requiring KU's debt to total capitalization not to exceed 70%, as calculated in accordance with the facilities, and other customary covenants. Additionally, subject to certain conditions, KU may request that the Syndicated Credit Facility's capacity be increased by up to $100 million.

(d) In April 2011, KU entered into a letter of credit facility that has been used to issue letters of credit to support outstanding tax-exempt bonds. The facility contains a financial covenant requiring KU's debt to total capitalization not to exceed 70%, as calculated in accordance with the credit facility. KU pays customary commitment and letter of credit fees under the new facility. In August 2011, KU amended its letter of credit facility such that the fees depend upon KU's senior secured long-term debt rating rather than its senior unsecured long-term debt rating.

In February 2012, KU established a commercial paper program for up to $250 million to provide an additional financing source to fund its short-term liquidity needs. Commercial paper issuances will be supported by KU's Syndicated Credit Facility.

See Note 12 for discussion of intercompany borrowings.

Long-term Debt

	2011 (a)	2010
First Mortgage Bonds (b)	$ 1,500	$ 1,500
Pollution Control Bonds (Collateral Series), due 2023-2037 (c)	351	351
Fair value adjustments from purchase accounting (d)	1	1
Unamortized discount	(10)	(11)
Total Long-term Debt	$ 1,842	$ 1,841

(a) Aggregate maturities of long-term debt are zero for each of 2012 through 2015, $250; 2016, $0; and $1,601 thereafter.

None of the debt securities outstanding have sinking fund requirements.

(b) At December 31, 2011 and December 31, 2010, interest rates range from 1.625% to 5.125%, and maturities range from 2015 to 2040.

KU's first mortgage bonds are secured by the lien of the KU 2010 Mortgage Indenture, which creates a lien, subject to certain exceptions and exclusions, on substantially all of KU's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity. The aggregate carrying value of the property subject to the lien was $4.1 billion and $4.0 billion at December 31, 2011 and December 31, 2010.

The KU first mortgage bonds were issued in 2010 in private offerings to qualified institutional buyers and other transactions not subject to registration requirements under the Securities Act of 1933. In April 2011, KU filed its 2011 Registration Statement with the SEC related to offers to exchange the first mortgage bonds with similar but registered securities. The 2011 Registration Statement became effective in June 2011 and the exchange was completed in July 2011, with substantially all securities being exchanged.

(c) In October 2010, KU issued a series of first mortgage bonds to the respective trustees of tax-exempt revenue bonds to secure its respective obligations to make payments with respect to each series of bonds. The first mortgage bonds were issued in the same principal amount, contain payment and redemption provisions that correspond to and bear the same interest rate as such tax-exempt revenue bonds. These first mortgage bonds were issued under the KU 2010 Mortgage Indenture and are secured as noted in (b) above. The related tax-exempt revenue bonds were issued by various governmental entities, principally counties in Kentucky, on behalf of KU. The related revenue bond documents allow KU to convert the interest rate mode on the bonds from time to time to a commercial paper rate, daily rate, weekly rate, term rate of at least one year or, in some cases, an auction rate or a LIBOR index rate.

At December 31, 2011, the aggregate tax-exempt revenue bonds issued on behalf of KU that were in a term rate mode totaled $27 million. The weighted average rate on these bonds was 5.83%. At December 31, 2010, the amounts that were in a term rate mode totaled $27 million. The weighted average rate on these bonds was 5.83%.

At December 31, 2011, the aggregate tax-exempt revenue bonds issued on behalf of KU that were in a variable rate mode totaled $324 million. The weighted average rate on these bonds was 0.15%. At December 31, 2010, the amounts that were in a variable rate mode totaled $324 million. The weighted average rate on these bonds was 0.38%.

Several series of the tax-exempt revenue bonds are insured by monoline bond insurers whose ratings were reduced due to exposures relating to insurance of sub-prime mortgages. Of the bonds outstanding, $96 million are in the form of insured auction rate securities, wherein interest rates are reset every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. During 2008, interest rates increased, and KU experienced failed auctions when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture. As noted above, the instruments governing these auction rate bonds permit KU to convert the bonds to other interest rate modes.

Certain variable rate tax-exempt revenue bonds totaling $228 million at December 31, 2011, are subject to tender for purchase by KU at the option of the holder and to mandatory tender for purchase by KU upon the occurrence of certain events.

(d) Reflects adjustments made to record KU's long-term debt at fair value at the time of acquisition of LKE in 2010.

Distributions, Capital Contributions and Related Restrictions

KU is subject to Section 305(a) of the Federal Power Act, which makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in capital account." The meaning of this limitation has never been clarified under the Federal Power Act. KU believes, however, that this statutory restriction, as applied to its circumstances, would not be construed or applied by the FERC to prohibit the payment from retained earnings of dividends that are not excessive and are for lawful and legitimate business purposes. Also, under Virginia law, KU is prohibited from making loans to affiliates without the prior approval of the VSCC.

There are no comparable statutes under Kentucky law applicable to KU. However, Orders from the KPSC require KU to obtain prior regulatory consent or approval before loaning funds to PPL. At December 31, 2011, the net restricted assets of KU were approximately $2.7 billion.

During the year ended December 31, 2011, KU paid dividends of $124 million to its parent, LKE. No capital contributions were received from LKE during this period.

In February 2012, KU filed an application with the FERC seeking authorization to pay dividends in the future based on retained earnings balances, which would be calculated ignoring the impact of the accounting for the acquisition by PPL. If approved, as of December 31, 2011, this would increase the balance available for dividends from KU by $1.4 billion. KU does not anticipate changing its dividend practices.

6. Acquisitions, Development and Divestitures

KU continuously evaluates opportunities for potential acquisitions, divestitures and development projects. Development projects are continuously reexamined based on market conditions and other factors to determine whether to proceed with the projects, sell, cancel or expand them, execute tolling agreements or pursue other options. Any resulting transactions may impact future financial results.

Acquisition

Pending Bluegrass CTs Acquisition

In September 2011, KU and LG&E entered into an Asset Purchase Agreement with Bluegrass Generation for the purchase of the Bluegrass CTs, aggregating approximately 495 MW, plus limited associated contractual arrangements required for operation of the units, for a purchase price of $110 million. Pursuant to the Asset Purchase Agreement, KU and LG&E will jointly acquire the Bluegrass CTs as tenants in common, with KU as owner of a 31% undivided interest, and LG&E as owner of a 69% undivided interest, in the purchased assets. The purchase is subject to receipt of approvals from the KPSC, the FERC, certain permit assignments or local approvals, and other conditions. Either party can terminate the Asset Purchase Agreement should the purchase transaction fail to occur by June 30, 2012.

Development

NGCC Construction

In September 2011, KU and LG&E requested KPSC approval to build a 640 MW NGCC at the existing Cane Run plant site in Kentucky. This project is also subject to certain regulatory approvals. Once all approvals are received, construction is expected to begin in 2012 and be complete by 2016. The project, which includes building a natural gas supply pipeline, has an expected cost of approximately $580 million. See Note 4 for additional information.

In conjunction with this request and to meet new, stricter federal EPA regulations, KU and LG&E anticipate retiring six older coal-fired electric generating units at the Cane Run, Green River and Tyrone plants, which have a combined summer rating of 797 MW. The Cane Run and Green River coal units will need to remain operational until the replacement generation and associated transmission projects are completed.

TC2

In January 2011, KU began dispatching electricity from TC2 to meet customer demand. See Note 11 for additional information regarding the construction of TC2.

7. Acquisition of LKE

In November 2010, KU issued debt totaling $1.5 billion. The majority of these proceeds was applied to repay borrowings from a PPL Energy Supply subsidiary. Such borrowings were incurred to permit LKE to repay certain indebtedness owed to affiliates of E.ON AG upon the closing of the acquisition. See Note 5 for additional information.

On November 1, 2010, PPL completed its acquisition of LKE and its subsidiaries. The push-down basis of accounting was used to record the fair value adjustments of assets and liabilities on LKE at the acquisition date. PPL paid cash consideration for the equity interests in LKE and its subsidiaries of $2,493 million and provided a capital contribution on November 1, 2010, of $1,565 million; included within this was the consideration paid of $2,656 million for KU. The allocation of the purchase price was based on the fair value of assets acquired and liabilities assumed.

The push-down accounting for the fair value of assets acquired and liabilities assumed was as follows.

Current assets	$ 341
Investments	30
PP&E	4,531
Other intangibles (current and noncurrent)	201
Regulatory and other noncurrent assets	274
Current liabilities, excluding current portion of long-term debt	(367)
PPL affiliate indebtedness	(1,331)
Long-term debt (current and noncurrent)	(352)
Other noncurrent liabilities	(1,278)
Net identifiable assets acquired	2,049
Goodwill	607
Net assets acquired and beginning equity balance on November 1, 2010	$ 2,656

Goodwill represents value paid for the rate regulated businesses of KU, which is located in a defined service area with a constructive regulatory environment, which provides for future investment, earnings and cash flow growth, as well as the talented and experienced workforce. KU's franchise value is being attributed to the going concern value of the business, and thus was recorded as goodwill rather than a separately identifiable intangible asset. None of the goodwill recognized is deductible for income tax purposes or included in customer rates.

Adjustments to KU's assets and liabilities that contributed to goodwill are as follows:

The fair value adjustment on the EEI investment was calculated using the discounted cash flow valuation method. The result was an increase in KU's value of the investment in EEI; the fair value of EEI was calculated to be $30 million and a fair value adjustment of $18 million was recorded on KU. The fair value adjustment to EEI is amortized over the expected remaining useful life of plant and equipment at EEI, which is estimated to be over 20 years.

The pollution control bonds, excluding the reacquired bonds, had a fair value adjustment of $1 million for KU. All variable bonds were valued at par while the fixed rate bonds were valued with a yield curve based on average credit spreads for similar bonds.

As a result of the purchase accounting associated with the acquisition, the following items had a fair value adjustment but no effect on goodwill as the offset was either a regulatory asset or liability. The regulatory asset or liability has been recorded to eliminate any ratemaking impact of the fair value adjustments:

- The value of OVEC was determined to be $126 million based upon an announced transaction by another owner. KU's investment in OVEC was not significant and the power purchase agreement was valued at $39 million for KU. An intangible asset was recorded with the offset to regulatory liability and is amortized using the units of production method until March 2026, the expiration date of the agreement at the date of the acquisition.

- KU recorded an emission allowance intangible asset and a regulatory liability as the result of adjusting the fair value of the emission allowances at KU. The emission allowance intangible of $9 million at KU represents allocated and purchased sulfur dioxide and nitrogen oxide emission allowances that were unused as of the valuation date or allocated for use in future years. KU previously recorded emission allowances as other materials and supplies. To conform to PPL's accounting policy all emission allowances are now recorded as intangible assets. The emission allowance intangible asset is amortized as the emission allowances are consumed, which is expected to occur through 2040.

- Coal contract intangible assets were recorded at KU for $145 million as well as a non-current liability of $22 million on the Balance Sheets. An offsetting regulatory asset was recorded for those contracts with unfavorable terms relative to market. An offsetting regulatory liability was recorded for those contracts that had favorable terms relative to market. All coal contracts held by KU, wherein it had entered into arrangements to buy amounts of coal at fixed prices from counterparties at a future date, were fair valued. The intangible assets and other liabilities, as well as the regulatory assets and liabilities, are being amortized over the same terms as the related contracts, which expire through 2016.

- Adjustments on November 1, 2010 were made to record LKE pension assets at fair value, remeasure its pension and postretirement benefit obligations at current discount rates and eliminate accumulated other comprehensive income (loss). An increase of $1 million in the liability balances of KU was recorded, due to the lowering of the discount rate; this was credited to the respective pension and postretirement liability balances with offsetting adjustments made to the related regulatory assets and liabilities.

The fair value of intangible assets and liabilities (e.g. contracts that have favorable or unfavorable terms relative to market), including coal contracts and power purchase agreements, as well as emission allowances, have been reflected on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the acquisition. As a result, management believes the regulatory assets and liabilities created to offset the fair value adjustments meet the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. KU's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU also considered whether a separate fair value should be assigned to KU's rights to operate within its various electric distribution service areas but concluded that these rights only provided the opportunity to earn a regulated return and barriers to market entry, which in management's judgment is not considered a separately identifiable intangible asset under applicable accounting guidance; rather, it is considered going-concern value, or goodwill.

8. Leases

E.W. Brown Combustion Turbines

KU and LG&E are participants in a sale-leaseback transaction involving two combustion turbines at the E.W. Brown generating plant. In December 1999, after selling their interests in the combustion turbines, KU and LG&E entered into an 18-year lease of the turbines. KU and LG&E provided funds to fully defease the lease and have the right to exercise an early purchase option contained in the lease after 15.5 years, which will occur in 2015. The financial statement treatment of this transaction is the same as if KU and LG&E had retained their ownership interest. Since the lease was defeased, there are no remaining minimum lease payments and all related PP&E is reflected on the Balance Sheets. See Note 10 for the balances included on the Balance Sheets related to this transaction. Depreciation expense was insignificant for all periods presented.

Upon a default under the lease, KU and LG&E are obligated to pay to the lessor their share of certain amounts. Primary events of default include loss or destruction of the combustion turbines, failure to insure or maintain the combustion turbines and unwinding of the transaction due to governmental actions. No events of default currently exist with respect to the lease. Upon any termination of the lease, whether by default or expiration of its term, title to the combustion turbines reverts to KU and LG&E. The maximum aggregate amount at December 31, 2011 that could be required to be paid by KU is $4 million and by LG&E is $2 million. LKE has guaranteed the payment of these potential default payments of KU and LG&E.

Other Leases

KU has entered into various agreements for the lease of office space, vehicles, land and other equipment.

Rent - Operating Leases

Rent expense for operating leases was as follows:

Successor		Predecessor
Year Ended December 31, 2011	Two Months Ended December 31, 2010	Ten Months Ended October 31, 2010
$ 10	$ 2	$ 8

Total future minimum rental payments for all operating leases are estimated to be:

2012	$ 9
2013	7
2014	6
2015	5
2016	2
Thereafter	4
Total	$ 33

9. Retirement and Postemployment Benefits

Defined Benefits

Although KU does not directly sponsor any defined benefit plans, it is allocated a portion of the funded status and costs of plans sponsored by LKE based on its participation in those plans, which management believes are reasonable. The defined benefit pension plans of LKE and its subsidiaries were closed to new salaried and bargaining unit employees hired after December 31, 2005. Employees hired after December 31, 2005 receive additional company contributions above the standard matching contributions to their savings plans. The actuarially determined obligations of current active employees and retired employees of KU are used as a basis to allocate total plan activity, including active and retiree costs and obligations. KU's allocated share of the funded status of the pension plans resulted in a liability of $83 million and $113 million at December 31, 2011 and 2010. KU's allocated share of other postretirement benefits was a liability of $62 million at December 31, 2011 and 2010.

The following table provides net periodic benefit costs charged to operating expense for January 1, 2011 through December 31, 2011, and November 1, 2010 through December 31, 2010, for the Successor, and January 1, 2010 through October 31, 2010, for the Predecessor.

Pension Benefits (a)

Successor		Predecessor
2011	**2010**	**2010**
$ 10	$ 2	$ 8

Other Postretirement Benefits (a)

Successor		Predecessor
2011	**2010**	**2010**
$ 4	$ 1	$ 3

(a) KU was allocated these costs of defined benefit plans sponsored by LKE, based on its participation in those plans, which management believes are reasonable.

Contributions

KU made contributions to the defined benefit pension plan in which is participates of $43 million and $13 million in 2011 and 2010. In 2012, KU made a contribution of $15 million to the pension plan.

KU is not required to make contributions to the other postretirement benefit plan that it participates in but has historically funded this plan in amounts equal to the postretirement benefit costs. KU funded this plan $7 million and $8 million in 2011 and 2010. Continuation of this past practice would cause KU to contribute $13 million to the other postretirement benefit plan in 2012.

Savings Plans

Substantially all of KU's employees are eligible to participate in deferred savings plans (401(k)s). Employer contributions to the plans were as follows.

Successor		Predecessor
Year Ended December 31, 2011	**Two Months Ended December 31, 2010**	**Ten Months Ended October 31, 2010**
$ 6	$ 1	$ 4

Health Care Reform

In March 2010, Health Care Reform was signed into law. Many provisions of Health Care Reform do not take effect for an extended period of time, and most will require the publication of implementing regulations and/or issuance of program guidelines. As a result of this enactment, KU was not impacted but will continue to monitor the potential impact of any changes to the existing provisions and implementation guidance related to Health Care Reform on its benefit programs.

10. Jointly Owned Facilities

At December 31, 2011 and 2010, the Balance Sheets reflect the owned interests in the facilities listed below.

	Ownership Interest	Electric Plant	Accumulated Depreciation	Construction Work in Progress
December 31, 2011				
Generating Plants				
Trimble County Units 7-10	63.00%	$ 109	$ 6	$ 5
E.W. Brown Units 6-7	62.00%	64	5	-
Trimble County Units 5-6	71.00%	66	2	4
Paddy's Run Unit 13 & E.W. Brown Unit 5	47.00%	39	2	4
Trimble County Unit 2	60.75%	758	35	17
December 31, 2010				
Generating Plants				
Trimble County Units 7-10	63.00%	$ 107	$ 1	$ 2
E.W. Brown Units 6-7	62.00%	64	2	-
Trimble County Units 5-6	71.00%	64	1	3
Paddy's Run Unit 13 & E.W. Brown Unit 5	47.00%	39	-	4
Trimble County Unit 2	60.75%	62	1	703

Each subsidiary owning these interests provides its own funding for its share of the facility. Each receives a portion of the total output of the generating plants equal to its percentage ownership. The share of fuel and other operating costs associated with the plants is included in the corresponding operating expenses on the Statements of Income.

11. Commitments and Contingencies

Energy Purchase Commitments

KU has a power purchase agreement with OVEC, extended in February 2011 to June 2040. FERC approval of the extension was received in May 2011, followed by KPSC and VSCC approvals in August 2011. Pursuant to the OVEC power purchase contract, KU is responsible for their pro-rata share of certain obligations of OVEC under defined circumstances. These potential liabilities include unpaid OVEC indebtedness as well as shortfall amounts in certain excess decommissioning costs and other post-employment and post-retirement benefit costs other than pension. KU’s proportionate share of OVEC's outstanding debt was $36 million at December 31, 2011. Future obligations for power purchases from OVEC are unconditional demand payments, comprised of annual minimum debt service payments, as well as contractually required reimbursement of plant operating, maintenance and other expenses as follows:

2012	$ 9
2013	9
2014	9
2015	10
2016	10
Thereafter	264
	$ 311

In addition, KU had total energy purchases under the OVEC power purchase agreement for the periods ended as follows:

Successor		Predecessor
Year Ended December 31, 2011	Two Months Ended December 31, 2010	Ten Months Ended October 31, 2010
$ 10	$ 2	$ 7

KU enters into purchase contracts to supply the coal and natural gas requirements for generation facilities and LG&E's gas supply operations. The coal contracts extend through 2016 and the natural gas contracts extend through 2013. KU also enters into contracts for other coal related consumables, coal transportation and fleeting services, which expire at different time periods through 2018. KU also has transportation contracts for natural gas that extend through 2018.

Legal Matters

KU is involved in legal proceedings, claims and litigation in the ordinary course of business. KU cannot predict the outcome of such matters, or whether such matters may result in material liabilities, unless otherwise noted.

TC2 Construction

In June 2006, KU and LG&E, as well as the Indiana Municipal Power Agency and Illinois Municipal Electric Agency (collectively, TC2 Owners), entered into a construction contract regarding the TC2 project. The contract is generally in the form of a turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price. During 2009 and 2010, the TC2 Owners received several contractual notices from the TC2 construction contractor asserting historical force majeure and excusable event claims for a number of adjustments to the contract price, construction schedule, commercial operations date, liquidated damages or other relevant provisions. In September 2010, the TC2 Owners and the construction contractor agreed to a settlement to resolve the force majeure and excusable event claims occurring through July 2010, under the TC2 construction contract, which settlement provided for a limited, negotiated extension of the contractual commercial operations date and/or relief from liquidated damage calculations. With limited exceptions, the TC2 Owners took care, custody and control of TC2 in January 2011. Pursuant to certain amendments to the construction agreement, the contractor will complete modifications to the combustion system prior to certain dates to allow operation of TC2 on all specified fuels categories. The provisions of the construction agreement relating to liquidated damages were also amended. In September 2011, the TC2 Owners and the construction contractor entered into a further amendment to the construction agreement settling, among other matters, certain historical change order, labor rate and prior liquidated damages amounts. The remaining issues are still under discussion with the contractor. KU cannot currently predict the outcome of this matter or the potential impact on the capital costs of this project.

Regulatory Issues

See Note 4 for information on regulatory matters related to utility rate regulation.

Enactment of Financial Reform Legislation

In July 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions that impose derivative transaction reporting requirements and require most over-the-counter derivative transactions to be executed through an exchange and to be centrally cleared. The Dodd-Frank Act also provides that the U.S. Commodity Futures Trading Commission (CFTC) may impose collateral and margin requirements for over-the-counter derivative transactions, as well as capital requirements for certain entity classifications. Final rules on major provisions in the Dodd-Frank Act are being established through rulemakings, and the CFTC generally has postponed implementation until the later of July 16, 2012 or when required key final rules are issued (e.g. definitional rules for "swap" and "swap dealer"). In order to comply with implementing regulations of the Dodd-Frank Act, KU likely will be faced with significant new recordkeeping and reporting requirements. Also, KU could face significantly higher operating costs or may be required to post additional collateral if it is subject to margin requirements as ultimately adopted in the implementing regulations of the Dodd-Frank Act. KU will continue to evaluate the provisions of the Dodd-Frank Act. At this time, KU cannot predict the impact that the law or its implementing regulations will have on its businesses or operations, or the markets in which it transacts business, but could incur material costs related to compliance with the Dodd-Frank Act.

FERC Market-Based Rate Authority

In November 1998, the FERC authorized KU to make wholesale sales of electric power and related products at market-based rates. In those orders, the FERC directed KU to file an updated market analysis within three years after the order, and every three years thereafter. Since then, periodic market-based rate filings with the FERC have been made by KU. Also, in June 2011, PPL filed its market-based rate update for the Southeast region, including KU. In June 2011, the FERC issued an Order approving KU's request for a determination that it no longer be deemed to have market power in the Big Rivers Electric Corporation balancing area and removing restrictions on their market-based rate authority in such region.

Currently, a seller granted FERC market-based rate authority may enter into power contracts during an authorized time period. If the FERC determines that the market is not workably competitive or that the seller possesses market power or is not charging "just and reasonable" rates, it may institute prospective action, but any contracts entered into pursuant to the FERC's market-based rate authority remain in effect and are generally subject to a high standard of review before the FERC can order changes. Recent court decisions by the U.S. Court of Appeals for the Ninth Circuit have raised issues that may make it more difficult for the FERC to continue its program of promoting wholesale electricity competition through market-based rate authority. These court decisions permit retroactive refunds and a lower standard of review by the FERC for changing power contracts, and could have the effect of requiring the FERC in advance to review most, if not all, power contracts. In June 2008, the U.S. Supreme Court reversed one of the decisions of the U.S. Court of Appeals for the Ninth Circuit, thereby upholding the higher standard of review for modifying contracts. At this time, KU cannot predict the impact of these court decisions on the FERC's future market-based rate authority program or on their businesses.

Energy Policy Act of 2005 - Reliability Standards

The NERC is responsible for establishing and enforcing mandatory reliability standards (Reliability Standards) regarding the bulk power system. The FERC oversees this process and independently enforces the Reliability Standards.

The Reliability Standards have the force and effect of law and apply to certain users of the bulk power electricity system, including electric utility companies, generators and marketers. The FERC has indicated it intends to vigorously enforce the Reliability Standards using, among other means, civil penalty authority. Under the Federal Power Act, the FERC may assess civil penalties of up to $1 million per day, per violation, for certain violations. The first group of Reliability Standards approved by the FERC became effective in June 2007.

KU monitors its compliance with the Reliability Standards and continue to self-report potential violations of certain applicable reliability requirements and submit accompanying mitigation plans, as required. The resolution of a number of potential violations is pending. Any regional reliability entity determination concerning the resolution of violations of the Reliability Standards remains subject to the approval of the NERC and the FERC. KU cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any, other than the amounts currently recorded.

In the course of implementing its program to ensure compliance with the Reliability Standards by KU, certain other instances of potential non-compliance may be identified from time to time.

Environmental Matters

Due to the environmental issues discussed below or other environmental matters, KU may be required to modify, curtail, replace or cease operating certain facilities or operations to comply with statutes, regulations and other requirements of regulatory bodies or courts.

<u>Air</u>

The Clean Air Act addresses, among other things, emissions causing acid deposition, installation of best available control technologies for new or substantially modified sources, attainment of national ambient air quality standards, toxic air emissions and visibility standards in the U.S. Amendments to the Clean Air Act requiring additional emission reductions have been proposed but are unlikely to be introduced or passed in this Congress. The Clean Air Act allows states to develop more stringent regulations and in some instances, as discussed below, Kentucky has done so.

To comply with air-related requirements and other environmental requirements as described below, KU's forecast for capital expenditures reflects a best estimate projection of expenditures that may be required within the next five years. Such projections are a combined $1.5 billion for KU (which includes $400 million associated with currently approved ECR plans through 2013 to achieve emissions reductions and manage coal combustion residuals, $900 million associated with the recently approved 2011 ECR Plans for additional expenditures to comply with new clean air rules and manage coal combustion residuals and an additional $200 million for other environmental expenditures). Actual costs (including capital, allowance purchases and operational modifications) may be significantly lower or higher depending on the final requirements and market conditions. Certain environmental compliance costs incurred by KU in serving KPSC jurisdictional customers are subject to recovery through the ECR. See Note 4 for additional information on the ECR plan.

CSAPR (formerly Clean Air Transport Rule)

In July 2011, the EPA signed the CSAPR, which finalizes and renames the Clean Air Transport Rule (Transport Rule) proposed in August 2010, and made revisions to the rule on February 7, 2012. The CSAPR replaces the EPA's previous CAIR which was struck down by the U.S. Court of Appeals for the District of Columbia Circuit (the Court) in July 2008. CAIR subsequently was effectively reinstated by the Court in December 2008, pending finalization of the Transport Rule. Like CAIR and the proposed Transport Rule, the CSAPR only applies to KU's coal generation facilities located in Kentucky.

The CSAPR is meant to facilitate attainment of ambient air quality standards for ozone and fine particulates by requiring reductions in sulfur dioxide and nitrogen oxides. The CSAPR established new sulfur dioxide emission allowance cap and trade programs that are completely independent of, and more stringent than, the current Acid Rain Program. The CSAPR also established new nitrogen oxides emission allowance cap and trade programs to replace the current programs. All trading is more restrictive than previously under CAIR. The CSAPR provides for two-phased programs of sulfur dioxide and nitrogen oxide emissions reductions, with initial reductions in 2012 and more stringent reductions in 2014.

In December 2011, the Court stayed implementation of the CSAPR and left CAIR in effect pending a final resolution on the merits of the validity of the rule. Oral argument on the various challenges to the CSAPR is scheduled for April 2012, and a final decision on the validity of the rule could be released as early as May 2012.

With respect to the KU coal-fired generating plants, the stay of the CSAPR will initially only impact the unit dispatch order. With the return of the CAIR and KU's significant number of sulfur dioxide allowances, those units will be dispatched with lower operating cost, but slightly higher sulfur dioxide and nitrogen oxide emissions. However, a key component of the Court's final decision, even if the CSAPR is upheld, will be whether the ruling delays the implementation of the CSAPR by one year for both Phases I and II, or instead still requires the significant sulfur dioxide and nitrogen oxide reductions associated with Phase II to begin in 2014. KU's CSAPR compliance strategy is based on over-compliance during Phase I to generate allowances sufficient to cover the expected shortage during the first two years of Phase II (2014 and 2015) when additional pollution control equipment will be installed. Should Phase I of the CSAPR be shortened to one year, it will be more difficult and costly to provide enough excess allowances in one year to meet the shortage projected for 2014 and 2015.

National Ambient Air Quality Standards

In addition to the reductions in sulfur dioxide and nitrogen oxide emissions required under the CSAPR for Kentucky plants, KU’s coal plants, may face further reductions in sulfur dioxide and nitrogen oxide emissions as a result of more stringent national ambient air quality standards for ozone, nitrogen oxide, sulfur dioxide and/or fine particulates. The EPA has recently finalized a new one-hour standard for sulfur dioxide, and states are required to identify areas that meet those standards and areas that are in non-attainment. For non-attainment areas, states are required to develop plans by 2014 to achieve attainment by 2017. For areas in attainment or that are unclassifiable, states are required to develop maintenance plans by mid-2013 that demonstrate continued attainment. KU anticipates that some of the measures required for compliance with the CSAPR such as upgraded or new sulfur dioxide scrubbers at some of its plants or retirement of the Green River and Tyrone plants, will also be necessary to achieve compliance with the new one-hour sulfur dioxide standard. If additional reductions were to be required, the economic impact could be significant.

Mercury and Other Hazardous Air Pollutants

In May 2011, the EPA published a proposed regulation providing for stringent reductions of mercury and other hazardous air pollutants. On February 16, 2012, the EPA published the final rule, known as the Mercury and Air Toxics Standards (MATS), with an effective date of April 16, 2012. The rule provides for a three-year compliance deadline with the potential for a one-year extension as provided under the statute. Based on its assessment of the need to install pollution control equipment to meet the provisions of the proposed rule, KU filed requests with the KPSC for environmental cost recovery to facilitate moving forward with plans to install environmental controls including sorbent injection and fabric-filter baghouses to remove certain hazardous air pollutants. Recovery of the cost of certain controls was granted by KPSC order issued in December 2011. The cost for these controls is reflected in the combined costs of $1.5 billion noted under "Air" above. KU has also announced the anticipated retirement of coal-fired generating units at the Green River and Tyrone plants and has filed requests with the KPSC for replacement of those units with natural gas-fired generating units to be constructed or purchased. With the publication of the final MATS rule, KU is currently assessing whether changes in the final rule warrant revision of its approved compliance plans. KU is continuing to conduct in-depth reviews of the MATS.

Regional Haze and Visibility

KU submitted analyses of the visibility impacts of its Best Available Retrofit Technology (BART) eligible sources to the Kentucky Division for Air Quality. In the event that the EPA determines that compliance with the CSAPR would be insufficient to meet the BART requirements, it would be necessary for KU to reassess its planned compliance measures.

New Source Review (NSR)

The NSR regulations require major new or modified sources of regulated pollutants to receive pre-construction and operating permits with limits that prevent the significant deterioration of air quality in areas that are in attainment of the ambient air quality standards for certain pollutants.

The EPA has continued its NSR enforcement efforts targeting coal-fired generating plants. The EPA has asserted that modification of these plants has increased their emissions and, consequently, that they are subject to stringent NSR requirements under the Clean Air Act.

In August 2007, KU received information requests for its Ghent plant, but has received no further communications from the EPA since providing their responses. KU cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any.

In March 2009, KU received a notice alleging that KU violated certain provisions of the Clean Air Act's rules governing NSR and prevention of significant deterioration by installing sulfur dioxide scrubbers and SCR controls at its Ghent generating plant without assessing potential increased sulfuric acid mist emissions. KU contends that the work in question, as pollution control projects, was exempt from the requirements cited by the EPA. In December 2009, the EPA issued an information request on this matter. KU has exchanged settlement proposals and other information with the EPA regarding imposition of additional permit limits and emission controls and anticipates continued settlement negotiations. In addition, any settlement or future litigation could potentially encompass a September 2007 notice of violation alleging opacity violations at the plant. Depending on the provisions of a final settlement or the results of litigation, if any, resolution of this matter could involve significant increased operating and capital expenditures. KU cannot predict the final outcome of this matter, but currently do not expect such outcome to result in material losses above the respective amounts accrued by KU.

If KU is found to have violated NSR regulations, KU would, among other things, be required to meet permit limits reflecting Best Available Control Technology (BACT) for the emissions of any pollutant found to have significantly increased due to a major plant modification. The costs to meet such limits, including installation of technology at certain units, could be significant.

States and environmental groups also have initiated enforcement actions and litigation alleging violations of the NSR regulations by coal-fired plants, and KU is unable to predict whether such actions will be brought against any of its plants.

TC2 Air Permit

The Sierra Club and other environmental groups petitioned the Kentucky Environmental and Public Protection Cabinet to overturn the air permit issued for the TC2 baseload generating unit, but the agency upheld the permit in an Order issued in September 2007. In response to subsequent petitions by environmental groups, the EPA ordered certain non-material changes to the permit which were incorporated into a final revised permit issued by the KDAQ in January 2010. In March 2010, the environmental groups petitioned the EPA to object to the revised state permit. Until the EPA issues a final ruling on the pending petition and all available appeals are exhausted, KU cannot currently predict the outcome of this matter or the potential impact on the capital costs of this project, if any.

Global Climate Change

There is concern nationally and internationally about global climate change and the possible contribution of GHG emissions including, most significantly, carbon dioxide, from the combustion of fossil fuels. This has resulted in increased demands for carbon dioxide emission reductions from investors, environmental organizations, government agencies and the international community. These demands and concerns have led to federal legislative proposals, actions at regional, state and local levels, litigation relating to GHG emissions and the EPA regulations on GHGs.

Greenhouse Gas Legislation

While climate change legislation was considered during the 111th Congress, the outcome of the 2010 elections has halted the debate on such legislation in the current 112th Congress. The timing and elements of any future legislation addressing GHG emission reductions are uncertain at this time. In the current Congress, legislation barring the EPA from regulating GHG emissions under the existing authority of the Clean Air Act has been passed by the U.S. House of Representatives. Various bills providing for barring or delaying the EPA from regulating GHG emissions have been introduced in the U.S. Senate, but the prospects for passage of such legislation remain uncertain. At the state level there are currently no prospects for such legislation in Kentucky.

Greenhouse Gas Regulations and Tort Litigation

As a result of the April 2007 U.S. Supreme Court decision that the EPA has the authority to regulate GHG emissions from new motor vehicles under the Clean Air Act, in April 2010, the EPA and the U.S. Department of Transportation issued new light-duty vehicle emissions standards that apply to 2012 model year vehicles. The EPA has also clarified that this standard triggers regulation of GHG emissions from stationary sources under the NSR and Title V operating permit provisions of the Clean Air Act starting in 2011. This means that any new sources or major modifications to existing sources causing a net significant emissions increase requires the BACT permit limits for GHGs. The EPA recently proposed guidance for conducting a BACT analysis for projects that trigger such a review. In addition, New Source Performance Standards for new and existing power plants were expected to be proposed in September 2011 and finalized in May 2012, but this has been delayed. The EPA is expected to announce a new schedule for this rulemaking in the future.

In November 2008, the Governor of Kentucky issued a comprehensive energy plan including non-binding targets aimed at promoting improved energy efficiency, development of alternative energy, development of carbon capture and sequestration projects, and other actions to reduce GHG emissions. In December 2009, the Kentucky Climate Action Plan Council was established to develop an action plan addressing potential GHG reductions and related measures. To date the state has yet to issue a final plan. The impact of any such plan is not now determinable, but the costs to comply with the plan could be significant.

A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities, and the law remains unsettled on these claims. In September 2009, the U.S. Court of Appeals for the Second Circuit in the case of AEP v. Connecticut reversed a federal district court's decision and ruled that several states and public interest groups, as well as the City of New York, could sue five electric utility companies under federal common law for allegedly causing a public nuisance as a result of their emissions of GHGs. In June 2011, the U.S. Supreme Court overturned the lower court and held that such federal common law claims were displaced by the Clean Air Act and regulatory actions of the EPA. In Comer v. Murphy Oil, the U.S. Court of Appeals for the Fifth Circuit declined to overturn a district court ruling that plaintiffs did not have standing to pursue state common law claims against companies that emit GHGs. The complaint in the Comer case named the previous indirect parent of LKE as a defendant based upon emissions from the Kentucky plants. In January 2011, the Supreme Court denied a petition to reverse the Court of Appeals' ruling. In May 2011, the plaintiffs in the Comer case filed a substantially similar complaint in federal district court in Mississippi against 87 companies, including KU and three other indirect subsidiaries of LKE, under a Mississippi statute that allows the re-filing of an action in certain circumstances. Additional litigation in federal and state courts over these issues is continuing. KU cannot predict the outcome of this litigation or estimate a range of reasonably possible losses, if any.

In 2011, KU and its jointly owned power plants emitted approximately 17 million tons of carbon dioxide compared with 18 million tons in 2010. All tons are U.S. short tons (2,000 lbs/ton).

<u>Water/Waste</u>

Coal Combustion Residuals (CCRs)

In June 2010, the EPA proposed two approaches to regulating the disposal and management of CCRs under the Resource Conservation and Recovery Act (RCRA). CCRs include fly ash, bottom ash and sulfur dioxide scrubber wastes. The first approach would regulate CCRs as a hazardous waste under Subtitle C of the RCRA. This approach would have very significant impacts on any coal-fired plant, and would require plants to retrofit their operations to comply with full hazardous waste requirements for the generation of CCRs and associated waste waters through transportation and disposal. This would also have a negative impact on the beneficial use of CCRs and could eliminate existing markets for CCRs. The second approach would regulate CCRs as a solid waste under Subtitle D of the RCRA. This approach would mainly affect disposal and most significantly affect any wet disposal operations. Under this approach, many of the current markets for beneficial uses would not be affected. Currently, KU expects that several of its plants in Kentucky could be significantly impacted by the requirements of Subtitle D of the RCRA, as these plants are using surface impoundments for management and disposal of CCRs.

The EPA has issued information requests on CCR management practices at numerous plants throughout the power industry as it considers whether or not to regulate CCRs as hazardous waste. KU has provided information on CCR management practices at most of its plants in response to the EPA's requests. In addition, the EPA has conducted follow-up inspections to evaluate the structural stability of CCR management facilities at several plants and KU has implemented certain actions in response to recommendations from these inspections.

The EPA is continuing to evaluate the unprecedented number of comments it received on its June 2010 proposed regulations. In October 2011, the EPA issued a Notice of Data Availability (NODA) that requests comments on selected documents that the EPA received during the comment period for the proposed regulations. Comments were submitted on the NODA in November 2011. In addition, the U.S. House of Representatives in October 2011 approved a bill to modify Subtitle D of the RCRA to provide for the proper management and disposal of CCRs and that would preclude the EPA from regulating CCRs under Subtitle C of the RCRA. The bill has been introduced in the Senate and the prospect for passage of this legislation is uncertain. In January 2012, a coalition of environmental groups filed a 60-day notice of intent to sue the EPA for failure to perform nondiscretionary duties under RCRA, which could require a hard deadline for EPA to issue strict CCR regulations. In February 2012, a CCR recycling company also issued a 60-day notice of intent to sue the EPA over its timeliness in issuing CCR regulations, but that company requests that the EPA take a Subtitle D approach that would allow for continued recycling of CCRs.

KU cannot predict at this time the final requirements of the EPA's CCR regulations or potential changes to the RCRA and what impact they would have on its facilities, but the economic impact could be significant.

Seepages and Groundwater Infiltration

Seepages or groundwater infiltration have been detected at active and retired wastewater basins and landfills at various plants. KU has completed or is completing assessments of seepages or groundwater infiltration at various facilities and is working with agencies to implement abatement measures, where required. A range of reasonably possible losses cannot currently be estimated.

Other Issues

In 2006, the EPA significantly decreased to 10 parts per billion (ppb) the drinking water standards related to arsenic. In Kentucky, this arsenic standard has been incorporated into the states' water quality standards and could result in more stringent limits in NPDES permits for KU’s plants. Subsequently, the EPA developed a draft risk assessment for arsenic that increases the cancer risk exposure by more than 20 times, which would lower the current standard from 10 ppb to 0.1 ppb. If the lower standard becomes effective, costly treatment would be required to attempt to meet the standard and, at this time, there is no assurance that it could be achieved. KU cannot predict the outcome of the draft risk assessment and what impact, if any, it would have on their facilities, but the costs could be significant.

The EPA is reassessing its polychlorinated biphenyls (PCB) regulations under the Toxics Substance Control Act, which currently allow certain PCB articles to remain in use. In April 2010, the EPA issued an Advanced Notice of Proposed Rulemaking for changes to these regulations. This rulemaking could lead to a phase-out of all PCB-containing equipment. KU cannot predict at this time the outcome of these proposed EPA regulations and what impact, if any, they would have on its facilities, but the costs could be significant.

The EPA finalized requirements in 2004 for new or modified cooling water intake structures. These requirements affect where generating facilities are built, establish intake design standards and could lead to requirements for cooling towers at new and modified power plants. Another rule, finalized in 2004, that addressed existing structures was withdrawn following a 2007 decision by the U.S. Court of Appeals for the Second Circuit. In 2009, however, the U.S. Supreme Court ruled that the EPA has discretion to use cost-benefit analysis in determining the best technology available for minimizing adverse environmental impact to aquatic organisms. The EPA published the proposed rule in April 2011. The industry and KU reviewed the proposed rule and submitted comments. The EPA is evaluating comments and meeting with industry groups to discuss options. The final rule is to be issued by July 2012. The proposed rule contains two requirements to reduce impact to aquatic organisms. The first requires all existing facilities to meet standards for the reduction of mortality of aquatic organisms that become trapped against water intake screens regardless of the levels of mortality actually occurring or the cost of achieving the requirements. The second requirement is to determine and install best technology available to reduce mortality of aquatic organisms that are pulled through the plant's cooling water system. A form of cost-benefit analysis is allowed for this second requirement. This process involves a site-specific evaluation based on nine factors including impacts to energy delivery reliability and remaining useful life of the plant. KU will be unable to determine the exact impact until a final rule is issued, the required studies have been completed, and each state in which they operate has decided how to implement the rule.

In October 2009, the EPA released its Final Detailed Study of the Steam Electric Power Generating effluent limitations guidelines and standards. Final regulations are expected to be effective in January 2014. KU expects the revised guidelines and standards to be more stringent than the current standards especially for sulfur dioxide scrubber wastewater and ash basin discharges, which could result in more stringent discharge permit limits. In the interim, KU is unable to predict whether the EPA and the states may impose more stringent limits on a case-by-case best professional judgment basis under existing authority as permits are renewed.

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County plant. In November 2010, the Cabinet issued a final order upholding the permit. In December 2010, the environmental groups appealed the order to state court. KU is unable to predict the outcome of this matter or estimate a range of reasonably possible losses, if any.

The EPA and the Army Corps of Engineers are working on a guidance document that will expand the federal government's interpretation of what constitutes "waters of the United States" (WOUS) subject to regulation under the Clean Water Act. This change has the potential to affect generation and delivery operations, with the most significant effect being the potential elimination of the existing regulatory exemption for plant waste water treatment systems. The costs that may be imposed as a result of any eventual expansion of this interpretation cannot reliably be estimated at this time.

Superfund and Other Remediation

KU is remediating or has completed the remediation of several sites that were not addressed under a regulatory program such as Superfund, but for which KU may be liable for remediation. These include a number of former coal gas manufacturing facilities in Kentucky previously owned or operated or currently owned by predecessors or affiliates of KU. There are additional sites, formerly owned or operated by KU predecessors or affiliates, for which KU lacks information on current site conditions and is therefore unable to predict what, if any, potential liability it may have.

Depending on the outcome of investigations at sites where investigations have not begun or been completed or developments at sites for which KU currently lacks information, the costs of remediation and other liabilities could be substantial. KU also could incur other non-remediation costs at sites included in current consent orders or other contaminated sites which could be significant. KU is unable to estimate a range of reasonably possible losses, if any, related to these matters.

The EPA is evaluating the risks associated with polycyclic aromatic hydrocarbons and naphthalene, chemical by-products of coal gas manufacturing. As a result of the EPA's evaluation, individual states may establish stricter standards for water quality and soil cleanup. This could require KU to take more extensive assessment and remedial actions at former coal gas manufacturing facilities. KU cannot estimate a range of reasonably possible losses, if any, related to these matters.

From time to time, KU undertakes remedial action in response to spills or other releases at various on-site and off-site locations, negotiates with the EPA and state and local agencies regarding actions necessary for compliance with applicable requirements, negotiates with property owners and other third parties alleging impacts from KU's operations, and undertakes similar actions necessary to resolve environmental matters which arise in the course of normal operations. Based on analyses to date, resolution of these general environmental matters is not expected to have a material adverse impact on KU's operations.

Future cleanup or remediation work at sites currently under review, or at sites not currently identified, may result in material additional costs for KU.

Electric and Magnetic Fields

Concerns have been expressed by some members of the public regarding potential health effects of power frequency EMFs, which are emitted by all devices carrying electricity, including electric transmission and distribution lines and substation equipment. Government officials in the U.S. have reviewed this issue. The U.S. National Institute of Environmental Health Sciences concluded in 2002 that, for most health outcomes, there is no evidence that EMFs cause adverse effects. The agency further noted that there is some epidemiological evidence of an association with childhood leukemia, but that the evidence is difficult to interpret without supporting laboratory evidence. KU believes research on EMF and health issues should continue and is taking steps to reduce EMFs, where practical, in the design of new transmission and distribution facilities. KU is unable to predict what effect, if any, the EMF issue might have on its operations and facilities, and the associated cost, or what, if any, liabilities it might incur related to the EMF issue.

Other

In the normal course of business, KU enters into agreements that provide financial performance assurance to third parties on behalf of certain affiliates. Such agreements include, for example, guarantees, stand-by letters of credit issued by financial institutions and surety bonds issued by insurance companies. These agreements are entered into primarily to support or enhance the creditworthiness attributed to an affiliate on a stand-alone basis or to facilitate the commercial activities in which these affiliates enter.

As described in the "Energy Purchase Commitments" section of this footnote, pursuant to a power purchase agreement with OVEC, KU is obligated to pay a demand charge which includes, among other charges, decommissioning costs, postretirement and post employment benefits. The demand charge is expected to cover KU's share of the cost of these items over the term of the contract. However, in the event there is a shortfall in covering these costs, KU is obligated to pay its share of the excess. The maximum exposure of this obligation cannot be determined at this time.

KU provides other miscellaneous guarantees through contracts entered into in the normal course of business. These guarantees are primarily in the form of indemnification or warranties related to services or equipment and vary in duration. The amounts of these guarantees often are not explicitly stated, and the overall maximum amount of the obligation under such guarantees cannot be reasonably estimated. Historically, no significant payments have been made with respect to these types of guarantees and the probability of payment/performance under these guarantees is remote.

12. Related Party Transactions

KU and subsidiaries of LKE and PPL engage in related party transactions. Transactions between KU and LKE subsidiaries are eliminated upon consolidation of LKE. Transactions between KU and PPL subsidiaries are eliminated upon consolidation of PPL. These transactions are generally performed at cost and are in accordance with FERC regulations under the Federal Power Act and the applicable KPSC and VSCC regulations.

Wholesale Sales and Purchases

KU and LG&E jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are reflected in the Statements of Income as "Electric revenue from affiliate" and "Energy purchases from affiliate" and are recorded at a price equal to the seller's fuel cost. Savings realized from such intercompany transactions are shared equally between the two companies. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

Intercompany Billings by LKS

LKS provides KU with a variety of centralized administrative, management and support services. The cost of these services is directly charged to the company or, for general costs that cannot be directly attributed, charged based on predetermined allocation factors, including the following measures: number of customers, total assets, revenues, number of employees and/or other statistical information. LKS charged the amounts in the table below, which LKE management believes are reasonable, including amounts that are further distributed between capital and expense.

Successor		Predecessor
Year Ended December 31, 2011	Two Months Ended December 31, 2010	Ten Months Ended October 31, 2010
$ 204	$ 34	$ 222

In addition, KU and LG&E provide services to each other and to LKS. Billings between KU and LG&E relate to labor and overheads associated with union and hourly employees performing work for the other company, charges related to jointly-owned generating units and other miscellaneous charges. Tax settlements between LKE and KU are reimbursed through LKS.

Intercompany Borrowings

In November 2010, a PPL Energy Supply subsidiary held term notes with KU. These notes were subsequently repaid and therefore no balances were outstanding at December 31, 2010. Interest on these notes was due monthly at interest rates between 4.24% and 7.04%. Interest on these notes is included in "Interest Expense with Affiliates." When balances were outstanding, interest on these notes was $2 million for 2010.

KU participates in an intercompany money pool agreement whereby LKE and/or LG&E make available to KU funds up to $500 million at an interest rate based on a market index of commercial paper issues. At December 31, 2011, there was no balance outstanding. At December 31, 2010, $10 million was outstanding. The interest rate for the period ended December 31, 2010 was 0.25%. Interest expense incurred on the money pool agreement with LKE and/or LG&E was not significant for 2011 or 2010.

Prior to PPL's acquisition of LKE in November 2010, KU had long-term loans from its former E.ON AG affiliates. During 2010, KU incurred interest expense on these debt arrangements of $62 million, which is included in the Statements of Income as "Interest Expense with Affiliate." Any such borrowings were repaid in 2010 prior to or at the time of the acquisition by PPL.

Other

See Note 1 for discussions regarding the intercompany tax sharing agreement and Note 5 for a discussion regarding capital transactions by KU. See Note 9 for discussions regarding intercompany allocations associated with defined benefits.

13. Other Income (Expense) - net

The breakdown of "Other Income (Expense) – net" was:

	Successor		Predecessor
	Year Ended December 31, 2011	Two Months Ended December 31, 2010	Ten Months Ended October 31, 2010
Other Income			
Equity in earnings of unconsolidated affiliate	$ 1	$ -	$ 3
Life insurance	-	-	2
Miscellaneous	-	-	1
Total Other Income	1	-	6
Other Expense			
Charitable contributions	1	-	1
Joint-use-asset depreciation	-	-	3
Miscellaneous	1	-	1
Total Other Expense	2	-	5
Other Income (Expense) - net	$ (1)	$ -	$ 1

14. Fair Value Measurements and Credit Concentration

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). KU uses, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques and option-pricing models), and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

Recurring Fair Value Measurements

The assets and liabilities measured at fair value were:

	December 31, 2011			
	Total	Level 1	Level 2	Level 3
Assets				
Cash and cash equivalents	$ 31	$ 31	$ -	$ -

	December 31, 2010			
	Total	Level 1	Level 2	Level 3
Assets				
Cash and cash equivalents	$ 3	$ 3	$ -	$ -
Restricted cash and cash equivalents (a)	1	1	-	-
Total assets	$ 4	$ 4	$ -	$ -

(a) Current portion is included in "Other current assets" on the Balance Sheets. Such amounts were insignificant at December 31, 2011 and December 31, 2010. The long-term portion is included in "Other noncurrent assets" on the Balance Sheets.

At December 31, 2011 and 2010, KU's price risk management assets and liabilities arising from energy commodities and interest rate swaps accounted for at fair value on a recurring basis were not significant.

Price Risk Management Assets/Liabilities - Energy Commodities

Energy commodity contracts are generally valued using the income approach, except for exchange-traded derivative gas, oil and emission allowance contracts, which are valued using the market approach and are classified as Level 1. When observable inputs are used to measure all or most of the value of a contract, the contract is classified as Level 2. Over-the-counter (OTC) contracts are valued using quotes obtained from an exchange, binding and non-binding broker quotes, prices posted by ISOs or published tariff rates. Furthermore, KU obtains independent quotes from the market to validate the forward price curves. OTC contracts include forwards, swaps, options and structured deals for electricity, gas, oil and/or emission allowances and may be offset with similar positions in exchange-traded markets. To the extent possible, fair value measurements utilize various inputs that include quoted prices for similar contracts or market-corroborated inputs. In certain instances, these instruments may be valued using models, including standard option valuation models and standard industry models. For example, the fair value of a structured deal that delivers power to an illiquid delivery point may be measured by valuing the nearest liquid trading point plus the value of the basis between the two points. Basis, in the context of derivatives and commodity trading, is the commodity price differential between two locations, products or time periods. The basis input may be from market quotes, FTR prices or historical prices.

Financial Instruments Not Recorded at Fair Value

The carrying values and estimated fair values of KU's non-trading financial instruments follow:

	December 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 1,842	$ 2,000	$ 1,841	$ 1,728

The carrying value of short-term debt (including notes between affiliates), when outstanding, represents or approximates fair value due to the variable interest rates associated with the financial instruments.

Credit Concentration Associated with Financial Instruments

KU enters into contracts with many entities for the purchase and sale of energy. Many of these contracts qualify for NPNS and as such, the fair value of these contracts is not reflected in the financial statements. However, the fair value of these contracts is considered when committing to new business from a credit perspective. See Note 15 for information on credit policies used by KU to manage credit risk, including master netting arrangements and collateral requirements.

At December 31, 2011, KU's credit exposure was not significant.

15. Derivative Instruments and Hedging Activities

Risk Management Objectives

KU has a risk management policy approved by LKE's Risk Management Oversight Committee (RMOC) to manage market risk and counterparty credit risk. The RMOC, comprised of certain members of senior management and chaired by the Chief Financial Officer, oversees the risk management function. Key risk control activities designed to ensure compliance with the risk policy and detailed programs include, but are not limited to, credit review and approval, validation of transactions and market prices, verification of risk and transaction limits, VaR analyses, portfolio stress tests, gross margin at risk analyses, sensitivity analyses and daily portfolio reporting, including open positions, determinations of fair value and other risk management metrics. During the second quarter of 2011, PPL's Risk Management Committee formally approved the inclusion of the risk programs for KU's parent, LKE, (acquired in November 2010) under the risk management policy.

Market Risk

Market risk is the potential loss KU may incur as a result of price changes associated with a particular financial or commodity instrument. KU utilizes forward contracts and swaps as part of risk management strategies, to minimize unanticipated fluctuations in earnings caused by changes in commodity prices. All derivatives are recognized on the Balance Sheets at their fair value, unless they qualify for NPNS.

By definition, the regulatory environment for KU significantly mitigates market risk. KU's rates are set to permit the recovery of prudently incurred costs, including certain mechanisms for fuel and environmental expenses. These mechanisms generally provide for timely recovery of market price and volumetric fluctuations associated with these expenses. KU primarily utilized forward financial transactions to manage price risk associated with expected economic generation capacity in excess of expected load requirements.

Credit Risk

Credit risk is the potential loss KU may incur due to a counterparty's non-performance, including defaults on payments and energy commodity deliveries.

KU’s credit risk stems from its commodity derivatives for contracts for energy sales and purchases. In the event a supplier of KU defaults on its obligation, KU would be required to seek replacement power or replacement fuel in the market. In general, incremental costs incurred by KU would be recoverable from customers in future rates.

KU has credit policies to manage its credit risk, including the use of an established credit approval process, daily monitoring of counterparty positions and the use of master netting agreements. These agreements generally include credit mitigation provisions, such as margin, prepayment or collateral requirements. KU may request the additional credit assurance, in certain circumstances, in the event that the counterparties' credit ratings fall below investment grade or their exposures exceed an established credit limit. See Note 14 for credit concentration associated with financial instruments.

Master Netting Arrangements

KU has elected not to offset net derivative positions against the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

KU had no obligation to return cash collateral under master netting arrangements at December 31, 2011 and December 31, 2010.

KU had not posted any cash collateral under master netting arrangements at December 31, 2011 and December 31, 2010.

Commodity Price Risk (Non-trading)

KU primarily utilized forward financial transactions to manage price risk associated with expected economic generation capacity in excess of expected load requirements. Hedge accounting treatment was not elected for these transactions; therefore, realized and unrealized gains and losses are recorded in the Statements of Income.

The net fair value of economic positions for KU at December 31, 2010 was not significant. There is no economic position at December 31, 2011. Unrealized gains (losses) for economic activity for KU in 2011and 2010 were not significant.

Accounting and Reporting

All derivative instruments are recorded at fair value on the Balance Sheet as an asset or liability unless they qualify for NPNS. Changes in the derivatives' fair value are recognized currently in earnings unless specific hedge accounting criteria are met.

See Note 1 for additional information on accounting policies related to derivative instruments.

There were no derivatives designated as hedging instruments as of December 31, 2011 and December 31, 2010. There were no after-tax balances of accumulated net gains (losses) in AOCI at December 31, 2011 and 2010. The gains and losses recognized in income on derivatives associated with commodity contracts were not significant for the periods ended December 31, 2011 and 2010.

16. Goodwill and Other Intangible Assets

Goodwill

As a result of the November 1, 2010 acquisition by PPL, KU recognized $607 million of goodwill. The allocation of goodwill was based on KU’s net asset values. See Note 7 for additional information.

Other Intangibles

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2011		December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Contracts (a)	$ 145	$ 43	$ 145	$ 3
Land and transmission rights (b)	8	-	8	-
Emission allowances (c)	3	-	9	-
OVEC power purchase agreement (d)	39	3	39	1
Total subject to amortization	$ 195	$ 46	$ 201	$ 4

(a) Gross carrying amount represents the fair value of contracts with terms favorable to market recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to these contracts, which is being amortized over the same period as the intangible assets, eliminating any income statement impact. See Note 4 for additional information.

(b) Gross carrying amount represents the fair value of land and transmission rights recognized as an intangible asset as a result of adopting PPL's accounting policies in the Successor period. Amortization expense is recovered through base rates and is expected to be insignificant for future periods.

(c) Represents the fair value of emission allowances recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to these emission allowances, which is being amortized as the emission allowances are consumed, eliminating any income statement impact. Consumption related to these emission allowances was $6 million and $1 million for 2011 and 2010.

(d) Gross carrying amount represents the fair value of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. See Note 4 for additional information.

Current intangible assets and long-term intangible assets are presented as "Other intangibles" in their respective areas on the Balance Sheets.

Amortization expense for the Successor, excluding consumption of emission allowances, was as follows:

	2011	2010
Intangible assets with regulatory offset	$ 42	$ 4

Amortization expense for each of the next five years, excluding consumption of emission allowances, is estimated to be:

	2012	2013	2014	2015	2016
Intangibles with regulatory offset	$ 24	$ 27	$ 23	$ 27	$ 13

17. Asset Retirement Obligations

KU’s AROs are primarily related to the final retirement of assets associated with generating units. KU's transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, no material AROs are recorded for transmission and distribution assets. As described in Notes 1 and 4, the accretion and depreciation expense recorded by KU is offset with a regulatory credit on the income statement, such that there is no earnings impact.

The changes in the carrying amounts of AROs were:

ARO at December 31, 2009, Predecessor	$	34
Accretion expense		2
Changes in estimated cash flow or settlement date		24
Obligations settled		-
ARO at October 31, 2010, Predecessor		60
Purchase accounting		(6)
ARO at December 31, 2010, Successor		54
Accretion expense		3
Obligations incurred		1
Changes in estimated cash flow or settlement date		3
Obligations settled		-
ARO at December 31, 2011, Successor	$	61

KU classified its AROs as long-term on the Balance Sheets at December 31, 2011 and 2010.

18. New Accounting Guidance Pending Adoption

Fair Value Measurements

Effective January 1, 2012, KU will prospectively adopt accounting guidance that was issued to clarify existing fair value measurement guidance as well as enhance fair value disclosures. The additional disclosures required by this guidance include quantitative information about significant unobservable inputs used for Level 3 measurements, qualitative information about the sensitivity of recurring Level 3 measurements, information about any transfers between Level 1 and 2 of the fair value hierarchy, information about when the current use of a non-financial asset is different from the highest and best use, and the hierarchy classification for assets and liabilities whose fair value is disclosed only in the notes to the financial statements.

Any fair value measurement differences resulting from the adoption of this guidance will be recognized in income in the period of adoption. The adoption of this guidance is not expected to have a significant impact on KU.

Testing Goodwill for Impairment

Effective January 1, 2012, KU will prospectively adopt accounting guidance which will allow an entity to elect the option to first make a qualitative evaluation about the likelihood of an impairment of goodwill. If, based on this assessment, the entity determines it is not more likely than not the fair value of a reporting unit is less than the carrying amount, the two-step goodwill impairment test is not necessary. However, the first step of the impairment test is required if an entity concludes it is more likely than not the fair value of a reporting unit is less than the carrying amount based on the qualitative assessment.

The adoption of this standard is not expected to have a significant impact on KU.

Improving Disclosures about Offsetting Balance Sheet Items

Effective January 1, 2013, KU will retrospectively adopt accounting guidance issued to enhance disclosures about financial instruments and derivative instruments that either (1) offset on the balance sheet or (2) are subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet.

Upon adoption, the enhanced disclosure requirements are not expected to have a significant impact on KU.

19. Notes to Statement of Cash Flows

Supplemental disclosures of cash flow information

	December 31, 2011	December 31, 2010
Cash paid during the period for:		
Income Taxes	$ 16	$ 62
Interest on borrowed money	59	3
Interest to affiliated companies on borrowed money	-	76
Other cash paid for interest	1	5

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				(2,854)
4	Total (lines 2 and 3)				(2,854)
5	Balance of Account 219 at End of Preceding Quarter/Year				(2,854)
6	Balance of Account 219 at Beginning of Current Year				(2,854)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				(464,223)
9	Total (lines 7 and 8)				(464,223)
10	Balance of Account 219 at End of Current Quarter/Year				(467,077)

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1				[redacted]	[redacted]
2				[redacted]	[redacted]
3			(2,854)	[redacted]	[redacted]
4			(2,854)	175,430,252	175,427,398
5			(2,854)	[redacted]	[redacted]
6			(2,854)	[redacted]	[redacted]
7				[redacted]	[redacted]
8			(464,223)	[redacted]	[redacted]
9			(464,223)	177,482,676	177,018,453
10			(467,077)	[redacted]	[redacted]

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Schedule Page: 122(a)(b) Line No.: 5 Column: e

The balance in Accumulated Other Comprehensive Income (219) was adjusted due to the purchase of KU by PPL in November 2010. The adjustment eliminated EEI's Accumulated Other Comprehensive Income to Other Paid-In Capital (211) related to its pension and postretirement plans. The following reflects the purchase accounting adjustment:

Accumulated Other Comprehensive Income (219) Without Purchase Accounting	$	(1,993,677)
Purchase Accounting Adjustment		1,990,823
Total for Accumulated Other Comprehensive Income (219)	$	(2,854)

Schedule Page: 122(a)(b) Line No.: 10 Column: e

The balance in Accumulated Other Comprehensive Income (219) was adjusted due to the purchase of KU by PPL in November 2010. The adjustment eliminated EEI's Accumulated Other Comprehensive Income to Other Paid-In Capital (211) related to its pension and postretirement plans. The following reflects the purchase accounting adjustment:

Accumulated Other Comprehensive Income (219) Without Purchase Accounting	$	(2,457,900)
Purchase Accounting Adjustment		1,990,823
Total for Accumulated Other Comprehensive Income (219)	$	(467,077)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	5,344,088,487	5,344,088,487
4	Property Under Capital Leases		
5	Plant Purchased or Sold	483,341	483,341
6	Completed Construction not Classified	1,098,123,813	1,098,123,813
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	6,442,695,641	6,442,695,641
9	Leased to Others		
10	Held for Future Use	792,600	792,600
11	Construction Work in Progress	339,711,432	339,711,432
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	6,783,199,673	6,783,199,673
14	Accum Prov for Depr, Amort, & Depl	2,395,037,773	2,395,037,773
15	Net Utility Plant (13 less 14)	4,388,161,900	4,388,161,900
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,377,291,009	2,377,291,009
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	17,746,764	17,746,764
22	Total In Service (18 thru 21)	2,395,037,773	2,395,037,773
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,395,037,773	2,395,037,773

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
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					31
					32
					33

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	44,456	
3	(302) Franchises and Consents	83,453	
4	(303) Miscellaneous Intangible Plant	52,198,462	9,594,810
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	52,326,371	9,594,810
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	10,874,264	
9	(311) Structures and Improvements	220,374,247	68,109,827
10	(312) Boiler Plant Equipment	2,030,074,230	608,522,192
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	230,029,313	70,911,528
13	(315) Accessory Electric Equipment	154,461,439	37,304,462
14	(316) Misc. Power Plant Equipment	26,889,111	3,418,881
15	(317) Asset Retirement Costs for Steam Production	52,467,836	4,391,368
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,725,170,440	792,658,258
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	879,312	
28	(331) Structures and Improvements	606,213	10,314
29	(332) Reservoirs, Dams, and Waterways	9,823,181	11,795,979
30	(333) Water Wheels, Turbines, and Generators	4,430,624	
31	(334) Accessory Electric Equipment	578,333	
32	(335) Misc. Power PLant Equipment	297,024	
33	(336) Roads, Railroads, and Bridges	176,359	
34	(337) Asset Retirement Costs for Hydraulic Production	57,609	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	16,848,655	11,806,293
36	D. Other Production Plant		
37	(340) Land and Land Rights	294,924	
38	(341) Structures and Improvements	36,018,414	
39	(342) Fuel Holders, Products, and Accessories	22,871,300	21,346
40	(343) Prime Movers	355,641,065	4,951,628
41	(344) Generators	59,406,099	-4,354
42	(345) Accessory Electric Equipment	43,585,285	903,426
43	(346) Misc. Power Plant Equipment	5,314,948	47,991
44	(347) Asset Retirement Costs for Other Production	17,791	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	523,149,826	5,920,037
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,265,168,921	810,384,588

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			44,456		2
27,534			55,919		3
3,244,352			58,548,920		4
3,271,886			58,649,295		5
					6
					7
		6,841	10,881,105		8
681,753		46,147,894	333,950,215		9
7,436,356		43,286,218	2,674,446,284		10
					11
1,816,683		20,540,362	319,664,520		12
909,711		10,778,469	201,634,659		13
365,962		68,368	30,010,398		14
56,695	-312,739		56,489,770		15
11,267,160	-312,739	120,828,152	3,627,076,951		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			879,312		27
			616,527		28
15,191			21,603,969		29
			4,430,624		30
			578,333		31
			297,024		32
			176,359		33
			57,609		34
15,191			28,639,757		35
					36
			294,924		37
			36,018,414		38
144,830			22,747,816		39
1,769,659			358,823,034		40
40,984			59,360,761		41
121,305			44,367,406		42
			5,362,939		43
			17,791		44
2,076,778			526,993,085		45
13,359,129	-312,739	120,828,152	4,182,709,793		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	25,588,288	24,823
49	(352) Structures and Improvements	16,310,678	1,943,583
50	(353) Station Equipment	195,876,642	11,852,881
51	(354) Towers and Fixtures	94,916,439	518,825
52	(355) Poles and Fixtures	137,558,272	11,844,477
53	(356) Overhead Conductors and Devices	155,508,419	5,460,193
54	(357) Underground Conduit	448,760	
55	(358) Underground Conductors and Devices	1,168,559	-767
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	86,951	453,048
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	627,463,008	32,097,063
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	5,017,402	299,592
61	(361) Structures and Improvements	6,990,052	682,043
62	(362) Station Equipment	133,712,656	7,983,930
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	274,717,925	14,938,232
65	(365) Overhead Conductors and Devices	263,190,276	21,524,743
66	(366) Underground Conduit	2,152,975	-272,573
67	(367) Underground Conductors and Devices	133,856,108	7,382,494
68	(368) Line Transformers	277,910,211	8,539,187
69	(369) Services	83,391,401	5,750,150
70	(370) Meters	68,368,139	978,001
71	(371) Installations on Customer Premises	18,260,864	3,023
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	81,419,905	3,731,131
74	(374) Asset Retirement Costs for Distribution Plant	287,376	499,659
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,349,275,290	72,039,612
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	2,567,847	
87	(390) Structures and Improvements	39,639,759	8,063,171
88	(391) Office Furniture and Equipment	24,034,572	7,887,260
89	(392) Transportation Equipment	18,776,803	1,187,914
90	(393) Stores Equipment	777,672	46,282
91	(394) Tools, Shop and Garage Equipment	7,963,168	1,331,142
92	(395) Laboratory Equipment	3,160,383	
93	(396) Power Operated Equipment	1,104,976	176,849
94	(397) Communication Equipment	27,988,155	2,896,916
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	126,013,335	21,589,534
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	126,013,335	21,589,534
100	TOTAL (Accounts 101 and 106)	5,420,246,925	945,705,607
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)	-483,341	
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	5,420,730,266	945,705,607

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			25,613,111		48
13,660			18,240,601		49
1,372,060		64,731	206,422,194		50
81,908			95,353,356		51
743,968			148,658,781		52
521,733			160,446,879		53
			448,760		54
6,243			1,161,549		55
					56
			539,999		57
2,739,572		64,731	656,885,230		58
					59
6,153			5,310,841		60
13,807			7,658,288		61
416,823		-79,332	141,200,431		62
					63
1,864,534			287,791,623		64
8,443,541		14,601	276,286,079		65
18,439			1,861,963		66
618,591			140,620,011		67
378,999			286,070,399		68
91,365			89,050,186		69
83,939		787,154	70,049,355		70
10,673			18,253,214		71
					72
3,616,160			81,534,876		73
			787,035		74
15,563,024		722,423	1,406,474,301		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			2,567,847		86
159,687			47,543,243		87
753,660			31,168,172		88
3,997,638			15,967,079		89
272,160			551,794		90
858,401		-787,154	7,648,755		91
3,160,383					92
107,599			1,174,226		93
12,506			30,872,565		94
					95
9,322,034		-787,154	137,493,681		96
					97
					98
9,322,034		-787,154	137,493,681		99
44,255,645	-312,739	120,828,152	6,442,212,300		100
					101
			-483,341		102
					103
44,255,645	-312,739	120,828,152	6,442,695,641		104

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Schedule Page: 204 Line No.: 15 Column: e

Reversal of asset retirement obligation (ARO) costs which do not qualify for ARO status.

Schedule Page: 204 Line No.: 41 Column: c

Reversal of amounts temporarily classified to this plant account in Completed Construction Not Classified-Electric (106), but at the time of final unitization were classified to the correct plant account.

Schedule Page: 204 Line No.: 55 Column: c

Reversal of amounts temporarily classified to this plant account in Completed Construction Not Classified-Electric (106), but at the time of final unitization were classified to the correct plant account.

Schedule Page: 204 Line No.: 66 Column: c

Reversal of amounts temporarily classified to this plant account in Completed Construction Not Classified-Electric (106), but at the time of final unitization were classified to the correct plant account.

Schedule Page: 204 Line No.: 102 Column: g

Loss on sale of 149 railcars as part of a lease transaction. The loss of $483,341 is recorded in Electric Plant Purchased of Sold (102). This transaction occurred in November 2010. The journal entries for this transaction were filed with the FERC on April 11, 2011.

Schedule Page: 204 Line No.: 104 Column: f

Transfer of Trimble County Unit 2 ("TC2") hyperbolic cooling tower of $17,830,912 and joint use assets of $102,997,240 from Electric Plant Held For Future Use to Electric Plant In Service. With limited exceptions, the Company took care, custody and control of TC2 on January 22, 2011.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Polo Club Blvd Distribution Substation	2/28/2010	2014	792,600
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
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29				
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31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			792,600

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	STEAM PRODUCTION MAJOR	
2	GHENT ASH POND/LANDFILL	75,946,156
3	BR3 SCR	59,109,861
4	BROWN ASH POND PHASE II	14,683,925
5	BROWN LANDFILL PHASE I	14,268,107
6	TC2 CAPITAL SPARES - KU	9,425,771
7	BR3 GENERATOR REWIND	5,710,020
8	BR 1, 2 & 3 FGD	5,160,835
9	BR ASH POND EXPANSION	4,567,533
10	GH2 ECONOMIZER REPLACEMENT	3,555,102
11	TC CCP LANDFILL PHASE 1 RAVINE-KU	2,725,696
12	GH2 REHEAT PENDANT ASSEMBLY	2,619,864
13	TC2 SPARES ECR KU	2,085,505
14	GH2 SUPERHEATER PLATEN REPLACEMENT	1,746,854
15	GH2 SAM MITIGATION	1,350,405
16	ENVIRONMENTAL COMPLIANCE STUDY-AIR	1,347,463
17	GH1 SAM MITIGATION	1,224,658
18	GH3 SCR CATALYST ADDITION	1,142,172
19	BR3 PRIMARY SUPERHEATER REPLACEMENT	1,081,155
20	GH3 SAM MITIGATION	1,034,645
21	TC CCP HOLCIM BARGE-KU	1,015,943
22	STEAM PRODUCTION MINOR	11,369,535
23		
24	HYDRAULIC POWER MAJOR	
25	DIX2 OVERHAUL	4,037,434
26	DIX1 OVERHAUL	1,670,331
27	HYDRAULIC POWER MINOR	630,665
28		
29	OTHER PRODUCTION MAJOR	
30	TC CT HOT GAS PATH INSPECTION KU#2 & CI PARTS	7,264,419
31	PR13 TURBINE BLADES & VANE REPLACEMENT	3,656,712
32	TC CT HOT GAS PATH INSPECTION #3	2,346,041
33	NEXT BASELOAD UNIT NGCC - CR	1,113,142
34	OTHER PRODUCTION MINOR	1,577,415
35		
36	TRANSMISSION MAJOR	
37	TC2 TRANSMISSION	5,094,757
38	PRIORITY REPLACEMENT TRANSMISSION LINES - KU	5,063,782
39	KMPA SUBSTATION	3,529,451
40	OHIO CO - MEREDITH 138 KV	3,159,749
41	WEST CLIFF REBUILD	2,824,488
42	ROUTINE SUBS	2,769,874
43	TOTAL	339,711,432

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	GRAHAMVILLE-DOE 161kV LINE	2,275,811
2	KU BREAKER REPLACEMENTS	1,825,248
3	NESC MAXIMUM OPERATING TEMP - PINEVILLE/HARLAN	1,724,851
4	GHENT 345kV BREAKER REPLACEMENT	1,670,243
5	EMS CC SWITCHOVER - KU	1,437,723
6	SPARE 345/138-161kV TRANSFORMER	1,414,623
7	TRANSMISSION MINOR	10,421,558
8		
9	DISTRIBUTION MAJOR	
10	KU POLE INSPECTION	6,464,136
11	CORNING SUBSTATION UPGRADE	2,129,328
12	BLACK BRANCH RD (UFLEX) SUB	1,462,953
13	UK WEST SUBSTATION ADDITION	1,292,043
14	RICHMOND 2 SUBSTATION UPGRADE	1,237,954
15	RINEYVILLE SUBSTATION PROJECT	1,142,493
16	DISTRIBUTION MINOR	22,173,248
17		
18	GENERAL PLANT MAJOR	
19	MICROWAVE BACKBONE RENOVATION	2,190,747
20	MOBILE AUTO DISPATCH	1,318,340
21	GENERAL PLANT MINOR	13,620,668
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	339,711,432

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	2,248,171,576	2,181,303,393	66,868,183	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	178,898,265	178,898,265		
4	(403.1) Depreciation Expense for Asset Retirement Costs	3,028,523	3,028,523		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	163,446	163,446		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-244,111	-244,111		
9	Fuel Stock	370,226	370,226		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	182,216,349	182,216,349		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	40,927,064	40,927,064		
13	Cost of Removal	14,750,261	14,750,261		
14	Salvage (Credit)	874,467	874,467		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	54,802,858	54,802,858		
16	Other Debit or Cr. Items (Describe, details in footnote):	1,762,637	1,762,637		
17	Other		66,868,183	-66,868,183	
18	Book Cost or Asset Retirement Costs Retired	-56,695	-56,695		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,377,291,009	2,377,291,009		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,252,189,529	1,252,189,529		
21	Nuclear Production				
22	Hydraulic Production-Conventional	8,177,521	8,177,521		
23	Hydraulic Production-Pumped Storage				
24	Other Production	178,012,565	178,012,565		
25	Transmission	326,310,841	326,310,841		
26	Distribution	558,694,385	558,694,385		
27	Regional Transmission and Market Operation				
28	General	53,906,168	53,906,168		
29	TOTAL (Enter Total of lines 20 thru 28)	2,377,291,009	2,377,291,009		

Schedule Page: 219 Line No.: 8 Column: c

Accrual for Cost of Removal and Salvage for ARO parent assets (FERC 254 and 403).

Schedule Page: 219 Line No.: 16 Column: c

Customer payments related to construction projects	$ 606,108
Reclass cost of removal and salvage on ARO parent assets for from Other Regulatory Liabilities (254) to Accumulated Provision for Depreciation (108) for assets which do not qualify as AROs	1,091,549
Reserve adjustments due to changes in asset retirement cost estimates	64,980
Total Other Debit or Credit Items	$ 1,762,637

Schedule Page: 219 Line No.: 17 Column: d

Plant Held For Future Use Accumulated Depreciation related to Trimble County Unit 2 ("TC2") assets was transferred to Plant in Service Accumulated Depreciation in January 2011. With limited exceptions, the Company took care, custody and control of TC2 on January 22, 2011.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Ohio Valley Electric Company (2.5%)			
2	Common Stock $100 par value, 2,500 shares			
3	250 shares	11/15/52		25,000
4	250 shares	1/14/53		25,000
5	250 shares	3/4/53		25,000
6	250 shares	4/15/53		25,000
7	250 shares	5/20/53		25,000
8	250 shares	6/22/53		25,000
9	500 shares	7/15/53		50,000
10	500 shares	7/31/53		50,000
11				
12	Electric Energy, Inc. (20%)			
13	Common Stock $100 par value, 12,400 shares			
14	3,500 shares	3/06/51		350,000
15	2,700 shares	8/3/53		270,000
16	6,200 shares	12/30/58		620,000
17	Equity Earnings			14,488,196
18	Other Comprehensive Income			-3,262,974
19	Purchase Accounting Adjustment			17,574,002
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	30,289,224

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
	25,000			1
				2
		25,000		3
		25,000		4
		25,000		5
		25,000		6
		25,000		7
		25,000		8
		50,000		9
		50,000		10
				11
				12
				13
		350,000		14
		270,000		15
		620,000		16
	1,923,199	16,411,395		17
-759,776		-4,022,750		18
-886,084		16,687,918		19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
-1,645,860	1,948,199	30,566,563		42

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Schedule Page: 224 Line No.: 1 Column: a

See Note 1 of Notes to Financial Statements under Cost Method Investment for a full description of the Ohio Valley Electric Company investment.

Schedule Page: 224 Line No.: 12 Column: a

See Note 1 of Notes to Financial Statement under Equity Method Investment for a full description of the Electric Energy, Inc.(EEI) investment.

Schedule Page: 224 Line No.: 19 Column: d

The balance in Investment in Subsidiary Companies (123.1) was adjusted due to the purchase of KU by PPL in November 2010. To reflect the fair value in Investment in Subsidiary Companies, a step-up in value compared to the net book value of the investment in EEI was recorded. The step-up in value was assumed to relate to EEI's plant and is amortized over the average life of EEI's plant assets. The following reflects the purchase accounting adjustment:

Investment in Subsidiary Companies (123.1) Without Purchase Accounting	$	12,715,222
Purchase Accounting Adjustment		17,721,683
2010 Amortization of Purchase Accounting Adjustment		(147,681)
Purchase Accounting Subtotal		17,574,002
Total for Investment in Subsidiary Companies (123.1)	$	30,289,224

Schedule Page: 224 Line No.: 19 Column: g

The balance in Investment in Subsidiary Companies (123.1) was adjusted due to the purchase of KU by PPL in November 2010. To reflect the fair value in Investment in Subsidiary Companies, a step-up in value compared to the net book value of the investment in EEI was recorded. The step-up in value was assumed to relate to EEI's plant and is amortized over the average life of EEI's plant assets. The following reflects the purchase accounting adjustment:

Investment in Subsidiary Companies (123.1) Without Purchase Accounting	$	13,878,645
Purchase Accounting Adjustment		17,721,683
2011 Amortization of Purchase Accounting Adjustment		(886,084)
2010 Amortization of Purchase Accounting Adjustment		(147,681)
Purchase Accounting Subtotal		16,687,918
Total for Investment in Subsidiary Companies (123.1)	$	30,566,563

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	94,898,528	96,745,429	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	22,853,191	24,309,683	Electric
8	Transmission Plant (Estimated)	1,828,758	2,652,973	Electric
9	Distribution Plant (Estimated)	7,878,294	7,074,276	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	32,560,243	34,036,932	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	8,854,899	9,914,010	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	136,313,670	140,696,371	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2012 No. (d)	2012 Amt. (e)
1	Balance-Beginning of Year	156,606.00	554,423	77,535.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Purchases from LG&E	24,072.00	356		
10					
11					
12					
13					
14					
15	Total	24,072.00	356		
16					
17	Relinquished During Year:				
18	Charges to Account 509	33,576.00	108,010		
19	Other:				
20	Charges to 143		4		
21	Cost of Sales/Transfers:				
22	Adjustment to final 2010	19.00	62		
23					
24					
25					
26					
27					
28	Total	19.00	62		
29	Balance-End of Year	147,083.00	446,703	77,535.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	1,106.50		1,106.50	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	1,106.50			
40	Balance-End of Year			1,106.50	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	1,106.50	3,106		
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2013		2014		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
77,535.00		77,535.00		2,015,910.00		2,405,121.00	554,423	1
								2
								3
				77,535.00		77,535.00		4
								5
								6
								7
								8
						24,072.00	356	9
								10
								11
								12
								13
								14
						24,072.00	356	15
								16
								17
						33,576.00	108,010	18
								19
							4	20
								21
						19.00	62	22
								23
								24
								25
								26
								27
						19.00	62	28
77,535.00		77,535.00		2,093,445.00		2,473,133.00	446,703	29
								30
								31
								32
								33
								34
								35
1,106.50		1,106.50		54,218.50		58,644.50		36
				2,213.00		2,213.00		37
								38
				1,106.50		2,213.00		39
1,106.50		1,106.50		55,325.00		58,644.50		40
								41
								42
								43
				1,106.50	187	2,213.00	3,293	44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2012 No. (d)	2012 Amt. (e)
1	Balance-Beginning of Year	26,783.00	12,156	21,841.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	6,508.00	7,499		
19	Other:				
20	Charges to 549/158	14,482.00	34		
21	Cost of Sales/Transfers:				
22	Sales to LG&E	1,900.00	864		
23	Transfer to OMU	204.00			
24	Adjustment to Final 2010	425.00			
25	Removed by EPA			21,841.00	
26					
27					
28	Total	2,529.00	864	21,841.00	
29	Balance-End of Year	3,264.00	3,759		
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2013		2014		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
21,841.00		21,841.00				92,306.00	12,156	1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						6,508.00	7,499	18
								19
						14,482.00	34	20
								21
						1,900.00	864	22
						204.00		23
						425.00		24
21,841.00		21,841.00				65,523.00		25
								26
								27
21,841.00		21,841.00				68,052.00	864	28
						3,264.00	3,759	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

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Schedule Page: 229 Line No.: 25 Column: d

During the fourth quarter of 2011, the EPA removed vintages 2012-2014 NOx Ozone Season and NOx Annual allowances as part of the discontinuance of the CAIR Ozone NOx Program. The EPA terms these transactions as "Program Termination."

On December 30, 2011, the D.C. Circuit Court issued an order staying the Cross-State Air Pollution Rule (CSAPR) pending the court's resolution of the petitions for review of the rule. It further ordered the EPA to continue administering CAIR and, in January 2012, the EPA re-issued vintage 2012 NOx Ozone Season and NOx Annual allowances, with the transaction name of “Return of CAIR Allowances.”

Schedule Page: 229 Line No.: 25 Column: f

During the fourth quarter of 2011, the EPA removed vintages 2012-2014 NOx Ozone Season and NOx Annual allowances as part of the discontinuance of the CAIR Ozone NOx Program. The EPA terms these transactions as "Program Termination."

On December 30, 2011, the D.C. Circuit Court issued an order staying the Cross-State Air Pollution Rule (CSAPR) pending the court's resolution of the petitions for review of the rule. It further ordered the EPA to continue administering CAIR and, in January 2012, the EPA re-issued vintage 2013 NOx Ozone Season and NOx Annual allowances, with the transaction name of “Return of CAIR Allowances.”

Schedule Page: 229 Line No.: 25 Column: h

During the fourth quarter of 2011, the EPA removed vintages 2012-2014 NOx Ozone Season and NOx Annual allowances as part of the discontinuance of the CAIR Ozone NOx Program. The EPA terms these transactions as "Program Termination."

On December 30, 2011, the D.C. Circuit Court issued an order staying the Cross-State Air Pollution Rule (CSAPR) pending the court's resolution of the petitions for review of the rule. It further ordered the EPA to continue administering CAIR and, in January 2012, the EPA re-issued vintage 2014 NOx Ozone Season and NOx Annual allowances, with the transaction name of “Return of CAIR Allowances.”

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	ASC 715 - Pension and Postretirement	117,274,368		228.3	4,010,222	113,264,146
2				190/282/		
3	ASC 740 - Income Taxes	13,595,336	64,099,977	283	2,482,958	75,212,355
4	Winter Storm 2009 (Aug-10 to Jul-20)	54,851,894		571/593	5,723,676	49,128,218
5	Asset Retirement Obligation	1,550,849	6,374,925	230/407.4	504,482	7,421,292
6	Coal Contracts (Nov-10 to Dec-15)	17,877,232		253	11,735,750	6,141,482
7	FERC Jurisdictional Pension Expenses	4,790,937	1,084,916			5,875,853
8				184/593/		
9	Mountain Storm 2009 (Nov-11 to Oct-16)		6,042,755	925	202,474	5,840,281
10	Unamortized Debt Expense (various)	4,626,424		181	216,672	4,409,752
11	VA Fuel Component	4,795,000	442,000	440-445	1,443,000	3,794,000
12	MISO Exit Fee (Mar-09 to Feb-14)	5,120,856		254/575.7	1,476,906	3,643,950
13	Wind Storm 2008 (Aug-10 to Jul-20)	2,104,036		593	219,551	1,884,485
14	Rate Case Expenses (Aug-10 to Jul-13)	1,734,768		928	671,524	1,063,244
15	EKPC FERC Transmission Costs -					
16	KY Portion (Mar-09 to Feb-14)	1,059,874		456/566	334,697	725,177
17	Corporate Headquarters Lease (Nov-10 to Jul-15)	900,950		253/931	221,286	679,664
18	KY Consortium for Carbon Storage (Aug-10 to Jul-14)	825,923		930.2	230,490	595,433
19	Carbon Management Research Group (Aug-10 to Jul-20)	162,197	102,440	930.2	102,440	162,197
20	General Management Audit - Electric		140,906			140,906
21	Rate Case Expenses (Mar-09 to Feb-12)	537,318		928	460,558	76,760
22	KY Fuel Adjustment Clause		9,084,000	440-445	9,084,000	
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44	TOTAL	231,807,962	87,371,919		39,120,686	280,059,195

Schedule Page: 232 Line No.: 3 Column: f

The regulatory asset represents the future revenue impact from the reversal of deferred income tax liability required for a tax depreciation basis adjustment and allowance for funds used during construction.

Schedule Page: 232 Line No.: 6 Column: f

The balance in Coal Contracts (Nov-10 to Dec-15) was adjusted due to the purchase of KU by PPL in November 2010. The adjustment represents the fair value measurement of coal supply contracts based upon the difference between estimated market prices of the coal to be purchased and the actual prices in the contracts. The balance will be amortized as the underlying purchase accounting adjustments are amortized. The following reflects the purchase accounting adjustment:

Coal Contracts (Nov-10 to Dec-15) Without Purchase Accounting	$ -
Purchase Accounting Adjustment	22,605,479
2011 Amortization of Purchase Accounting Adjustment	(11,735,750)
2010 Amortization of Purchase Accounting Adjustment	(4,728,247)
Total for Coal Contracts (Nov-10 to Dec-15)	$ 6,141,482

Schedule Page: 232 Line No.: 9 Column: c

In December 2009, there was a major snow storm in KU’s Virginia service area causing approximately 30,000 customer outages. During the 2009 Virginia Annual Information Filing (“AIF”), KU requested the Virginia Commission establish a regulatory asset and defer for future recovery $6,041,882 in incremental operation and maintenance expenses related to the storm restoration. In March 2011, the Virginia Commission issued a Staff Report on KU's 2009 AIF, Case No. PUE-2010-00031, stating that the Staff considers the storm damage to be extraordinary, non-recurring and material to KU. The Staff Report also recommended establishing a regulatory asset for these costs, with recovery over a five year period upon approval in the next base rate case. In March 2011, a $6,041,882 regulatory asset was established for actual costs incurred. In April 2011, KU filed an application with the Virginia Commission requesting an annual increase in electric base rates for the Virginia jurisdictional customers including recovery of the storm costs over five years. The Virginia Commission approved the storm regulatory asset costs within KU's request for increase in annual base rates with amortization beginning in November 2011.

Schedule Page: 232 Line No.: 10 Column: f

The balance represents the reclassification from Unamortized Debt Expense (various) due to the purchase of KU by PPL in November 2010, as these costs are considered to have no fair value in purchase accounting under US GAAP. However, KU receives recovery of these costs in rates through the embedded cost of capital. The following reflects the purchase accounting adjustment:

Unamortized Debt Expense (various) Without Purchase Accounting	$ -
Purchase Accounting Adjustment	4,662,536
2011 Amortization of Purchase Accounting Adjustment	(216,672)
2010 Amortization of Purchase Accounting Adjustment	(36,112)
Total for Unamortized Debt Expense (various)	$ 4,409,752

Schedule Page: 232 Line No.: 17 Column: f

The balance in Corporate Headquarters Lease (Nov-10 to Jul-15) was adjusted due to the purchase of KU by PPL in November 2010. The adjustment represents the fair value measurement of a lease contract based upon the difference between the estimated market price of the leased property and the actual lease costs. The following reflects the purchase accounting adjustment:

Corporate Headquarters Lease (Nov-10 to Jul-15) Without

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Purchase Accounting	$	-
Purchase Accounting Adjustment		900,950
2011 Amortization of Purchase Accounting Adjustment		(221,286)
Total for Corporate Headquarters Lease (Nov-10 to Jul-15)	$	679,664

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Goodwill	607,404,368				607,404,368
2						
3	Coal Contracts					
4	(Nov-10 to Dec-16)	141,581,000	1,814,173	254	41,621,407	101,773,766
5						
6	Key Man Life Insurance	38,822,902	2,615,229	426.2	635,959	40,802,172
7						
8	OVEC Power Purchase Contract					
9	(Nov-10 to Mar-26)	38,117,876		254	2,432,244	35,685,632
10						
11	Valuation of SO2 Allowances					
12	(Nov-10 to Dec-40)	2,661,489	25,976	254	183,898	2,503,567
13						
14	Valuation of NOx Ozone					
15	Allowances (Nov-10 to Dec-11)	335,785		254	335,785	
16						
17	Valuation of NOx Annual					
18	Allowances (Nov-10 to Dec-11)	5,278,036		254	5,278,036	
19						
20	Customer Credit Accounts					
21	Receivable		366,523	923	80,027	286,496
22						
23	Carrollton Sale/Leaseback					
24	(Aug-06 to Jul-23)	55,515		931	4,412	51,103
25						
26	Financing Expenses	257,235	2,275,638	181/131	2,532,247	626
27						
28	Cellular Antenna Charges		166			166
29						
30	Land Options	17,528		921	17,528	
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45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	834,531,734				788,507,896

Schedule Page: 233 Line No.: 1 Column: f

The Goodwill balance of $607,404,368 represents Kentucky Utilities Company's franchise value as a result of the acquisition by PPL Corporation in November 2010 which is attributed to the going concern value of the business.

Schedule Page: 233 Line No.: 4 Column: f

The balance of $101,773,766 relates to the fair value measurement of $144,919,879 for Kentucky Utilities Company's coal contracts that was recognized as a result of the acquisition by PPL Corporation in November 2010. The variance is 14 months of amortization in 2010 and 2011.

Schedule Page: 233 Line No.: 9 Column: f

The balance of $35,685,632 relates to the fair value measurement of $38,582,028 for the power purchase contract between Kentucky Utilities Company and Ohio Valley Electric Corporation that was recognized as a result of the acquisition by PPL Corporation in November 2010. The variance is 14 months of amortization in 2010 and 2011.

Schedule Page: 233 Line No.: 12 Column: f

The balance of $2,503,567 relates to the fair value measurement of $2,681,473 for KU's SO2 emission allowances that was recognized as a result of the acquisition by PPL in November 2010. The variance is 14 months of amortization in 2010 and 2011.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Pensions	-16,046,481	-15,715,422
3	Other Post Retirement & Employment Benefits	24,640,583	24,891,486
4	Regulatory Tax Adjustments	8,802,410	71,653,624
5	Environmental Cost Recovery	12,480,701	2,221,976
6	Vacation Pay	2,002,165	1,985,057
7	Other - See Notes for Detail	83,088,497	58,784,885
8	TOTAL Electric (Enter Total of lines 2 thru 7)	114,967,875	143,821,606
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	405,070	445,820
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	115,372,945	144,267,426

Notes

	Bal. at Beg. of Year	Bal. at End of Year
VA Fuel Clause	$(1,865,255)	$(1,475,866)
Workers' Compensation	942,435	1,048,490
State Tax Adjustment	703,518	(703,273)
Bad Debt Reserve	837,841	779,678
Demand Side Management	1,751,866	901,750
Contingent Liability	383,543	536,393
Other	(527,332)	176,980
	-----------	-----------
Total Line 7 without Purchase Accounting:	$ 2,226,616	$ 1,264,152
Purchase Accounting Adjustments (PAA):		
PAA – pollution control bonds	451,806	451,806
Amortization of PAA – pollution control bonds		
2011		(25,793)
2010	(4,299)	(4,299)
PAA – regulatory liability for power purchase contract	15,008,409	15,008,409
Amortization of PAA - reg. liab. for power purchase contract		
2011		(946,143)
2010	(180,555)	(180,555)
PAA – regulatory liability for emission allowances	3,601,785	3,601,785
Amortization of PAA - reg. liab. for emission allowances		
2011		(2,245,208)
2010	(382,690)	(382,690)
PAA – regulatory liability for coal supply contracts	56,373,833	56,373,833
Amortization of PAA - reg. liab. for coal supply contracts		
2011		(15,485,014)
2010	(1,298,823)	(1,298,823)
Purchase Accounting Adjustment – coal supply contracts	8,793,531	8,793,531
Amortization of PAA – coal supply contracts		
2011		(4,565,207)
2010	(1,839,288)	(1,839,288)
PAA – rent commitment	350,470	350,470
Amortization of PAA – rent commitment		
2011		(73,783)
2010	(12,298)	(12,298)

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (continued)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

	-----------	-----------
Total Line 7 with Purchase Acctg	$83,088,497	$58,784,885
	===========	===========

	Bal. at Beg. of Year	Bal. at End of Year
Environmental Assessment	$389,000	$389,000
Other	16,070	56,820
	-----------	----------
Total Line 17	$405,070	$445,820
	===========	===========

Balance of Beginning of Year	$115,372,945
Less Debits to:	
Acct 410.1	61,170,289
Acct 410.2	94,672
Plus Credits to:	
Acct 411.1	17,883,233
Acct 411.2	133,690
Other Balance Sheet Accounts	72,142,519

Balance at End of Year	$144,267,426
	===========

Note: Some beginning balance amounts were reclassified from prior years' ending balance for presentation purposes, total beginning balance deferrals did not change.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock			
2	Common Stock, Without Par Value	80,000,000		
3	Total Common	80,000,000		
4				
5	Preferred and Preference Stock			
6	Preferred Stock, Without Par Value	5,300,000		
7	Preference Stock, Without Par Value	2,000,000		
8	Total Preferred and Preference	7,300,000		
9				
10				
11	Note:			
12	There is no Call Price for Common Stock,			
13	Without Par Value			
14				
15	The Common Stock of Kentucky Utilities Company			
16	is owned by its parent company,			
17	LG&E and KU Energy LLC			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
37,817,878	308,139,978					2
37,817,878	308,139,978					3
						4
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Schedule Page: 250 Line No.: 8 Column: a

No shares of preferred or preference stock remain issued or outstanding.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1		
2	Account 211:	
3	Contributed Capital - Misc.	2,348,446,834
4		
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40	TOTAL	2,348,446,834

Schedule Page: 253 Line No.: 3 Column: b

The balance in Other Paid-in Capital (208-211) was adjusted due to the purchase of KU by PPL in November 2010. To reflect the fair value, the balance was adjusted for a step-up in value compared to the net book value of the investment in EEI net of deferred taxes, the fixed rate pollution control bonds net of taxes and goodwill. The balance also includes elimination of Retained Earnings (215, 215.1, 216) at October 31, 2010. See footnotes for Page 110, Lines 21, Column c, Page 110, Line 78, Column c, Page 110, Line 82, Column c, Page 112, Line 11, Column c, Page 112, Line 21, Column c and Page 112, Line 64, Column c. The following reflects the purchase accounting adjustment:

Other Paid-in Capital (208-211) Without Purchase Accounting	$ 315,858,083
Purchase Accounting Adjustment - goodwill	607,404,368
Purchase Accounting Adjustment – pollution control bonds	(709,649)
Purchase Accounting Adjustment – EEI investment	7,569,645
Purchase Accounting Adjustment – prior retained earnings	1,418,324,387
Total for Other Paid-in Capital (208-211)	$ 2,348,446,834

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CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Expenses on Common Stock	321,289
2		
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8		
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21		
22	TOTAL	321,289

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 (1):		
2	Pollution Control Bonds: (2)		
3	Mercer County 2000 Series A, due 05/01/2023, Variable	12,900,000	607,408
4	Carroll County 2002 Series A, due 02/01/2032, Variable	20,930,000	120,138
5	Carroll County 2002 Series B, due 02/01/2032, Variable	2,400,000	83,078
6	Muhlenberg County 2002 Series A, due 02/01/2032, Variable	2,400,000	93,078
7	Mercer County 2002 Series A, due 02/01/2032, Variable	7,400,000	92,678
8	Carroll County 2002 Series C, due 10/01/2032, Variable	96,000,000	2,150,595
9	Carroll County 2004 Series A, due 10/01/2034, Variable	50,000,000	1,483,449
10	Carroll County 2006 Series B, due 10/01/2034, Variable	54,000,000	1,313,275
11	Carroll County 2007 Series A, due 02/01/2026, 5.750%	17,875,000	638,428
12	Trimble County 2007 Series A, due 03/01/2037, 6.000%	8,927,000	471,138
13	Carroll County 2008 Series A, due 02/01/2032, Variable	77,947,405	796,036
14			
15	First Mortgage Bonds: (3)		
16	2010 due 11/01/2015, 1.625%	250,000,000	2,261,768
17			875,000 D
18	2010 due 11/01/2020, 3.250%	500,000,000	4,156,684
19			1,890,000 D
20	2010 due 11/01/2040, 5.125%	750,000,000	7,480,434
21			8,137,500 D
22	TOTAL ACCOUNT 221	1,850,779,405	32,650,687
23			
24	ACCOUNT 223 :		
25	TOTAL ACCOUNT 223		
26			
27	ACCOUNT 224 (4):		
28	Purchase Accounting Adjustments for Fair Value Measurement		
29	Carroll County 2007 Series A, due 02/01/2026, 5.750%	804,375	
30	Trimble County 2007 Series A, due 03/01/2037, 6.000%	357,080	
31	TOTAL ACCOUNT 224	1,161,455	
32			
33	TOTAL	1,851,940,860	32,650,687

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
05/19/2000	05/01/2023	05/19/2000	05/01/2023	12,900,000	24,276	3
05/23/2002	02/01/2032	05/23/2002	02/01/2032	20,930,000	173,627	4
05/23/2002	02/01/2032	05/23/2002	02/01/2032	2,400,000	19,490	5
05/23/2002	02/01/2032	05/23/2002	02/01/2032	2,400,000	19,108	6
05/23/2002	02/01/2032	05/23/2002	02/01/2032	7,400,000	58,916	7
10/03/2002	10/01/2032	10/03/2002	10/01/2032	96,000,000	254,411	8
10/20/2004	10/01/2034	10/20/2004	10/01/2034	50,000,000	103,260	9
02/23/2007	10/01/2034	02/23/2007	10/01/2034	54,000,000	112,838	10
05/24/2007	02/01/2026	05/24/2007	02/01/2026	17,875,000	1,027,813	11
05/24/2007	03/01/2037	05/24/2007	03/01/2037	8,927,000	535,620	12
10/17/2008	02/01/2032	10/17/2008	02/01/2032	77,947,405	161,191	13
						14
						15
11/16/2010	11/01/2015	11/16/2010	11/01/2015	250,000,000	4,062,500	16
						17
11/16/2010	11/01/2020	11/16/2010	11/01/2020	500,000,000	16,250,000	18
						19
11/16/2010	11/01/2040	11/16/2010	11/01/2040	750,000,000	38,437,500	20
						21
				1,850,779,405	61,240,550	22
						23
						24
						25
						26
						27
						28
		11/1/2010	02/01/2026	742,838	-52,745	29
		11/1/2010	03/01/2037	341,260	-13,560	30
				1,084,098	-66,305	31
						32
				1,851,863,503	61,174,245	33

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Schedule Page: 256 Line No.: 1 Column: a

(1) Per instruction 9 concerning the treatment of unamortized debt expense, premium or discount – debt premium and expenses are being amortized over the lives of the related issues.

(2) Pollution control series bonds are obligations of Kentucky Utilities Company (KU), issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates KU to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds.

(3) In November 2010, KU requested and was granted, authorization to issue first mortgage bonds totaling $1.5 billion by the Kentucky Public Service Commission in its September 30, 2010, Order in Case No. 2010-00206, The Commonwealth of Virginia State Corporation Commission in its October 19, 2010, Order in Case No. PUE-2010-00061, and the Tennessee Regulatory Authority in its October 21, 2010, Order in Docket No. 10-00119. The Company used the proceeds to repay the loans from a PPL subsidiary and for general corporate purposes. The first mortgage bonds were issued at a discount.

In April 2011, KU filed 2011 Registration Statements with the SEC related to offers to exchange securities issued in November 2010 in transactions not registered under the Securities Act of 1933 with similar but registered securities. The 2011 Registration Statements became effective in June 2011 and the exchanges were completed in July 2011, with substantially all securities being exchanged.

As of December 31, 2011, all of the Company’s long-term debt is collateralized by a first mortgage lien on substantially all of the assets of the Company in Kentucky.

(4) On November 1, 2010, PPL completed its acquisition of E.ON U.S., the Company's parent. Upon completion of the acquisition, E.ON U.S. was renamed LG&E and KU Energy LLC (LKE). PPL used push-down accounting for the acquisition, and as a result, the Company adjusted its assets and liabilities to reflect their fair values on the acquisition date.

The following pollution control bonds with coupon rates listed below were fair valued as a result of the PPL acquisition:

Bond Issue	(221) Principal	(224) Fair Value Adjustment	Total Purchase Accounting
Carroll County 2007 Series A, due 2/1/2026, 5.750%	$17,875,000	$804,375	$18,679,375
Trimble County 2007 Series A, due 3/1/2037, 6.000%	$ 8,927,000	$357,080	$ 9,284,080

The purchase accounting adjustments were recorded to Other Long-Term Debt (224) and are being amortized over the lives of the related issues to Interest on Long-Term Debt (427).

Schedule Page: 256 Line No.: 1 Column: i

Interest on Bonds and Revolving Credit: (221/222/224/231):

Total Account (221)	$61,240,550
Total Account (224)	(66,305)
Total Account (427)	$61,174,245

Interest on Advances to Associated Companies (223):

Advances from Associated Companies (223)	$ -
Other Short Term Interest	6,321
Total Account (430)	$ 6,321

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	177,482,676
2		
3		
4	Taxable Income Not Reported on Books	
5	See Footnote	4,288,875
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Footnote	136,022,636
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Footnote	9,066,314
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Footnote	301,805,465
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	6,922,408
28	Show Computation of Tax:	
29		
30	Federal Tax Net Income	
31	35% Rounded	2,422,843
32	Add: Adjustments of Prior Years' Taxes to Actual and Other	-10,286,191
33		
34	Total	-7,863,348
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 5 Column: b

Contributions in Aid of Construction	$ 4,002,210
Customer Advances for Construction	286,665

Total	$ 4,288,875
	==========

Schedule Page: 261 Line No.: 10 Column: b

Federal Income Taxes:	
Provision for Deferred Taxes	$110,707,112
AFUDC Flow Through	957,338
Amortization of Regulatory Expenses	1,132,082
Contingent Liabilities	392,930
Capitalized Interest	9,467,072
KCCS Regulatory Asset	230,490
Emission Allowances	116,117
MISO Exit Fees-Transmission	1,862,465
Over/Under Collections - VA Fuel Clause	1,001,000
Pensions	1,011,110
Performance Incentive	434,512
Postemployment	1,195,248
Asset Retirement Obligations	2,334,470
Spare Parts Regulatory Liability	2,084,703
Non-Deductible Expenses	1,102,127
Amortization Loss on Reacquired Debt	604,973
Workers' Compensation	272,634
Other	198,557

Total Without Purchase Accounting	$135,104,940
Purchase Accounting Adjustment:	
EEI Investment	886,084
FMV Leases	31,612

Total	$136,022,636
	============

Schedule Page: 261 Line No.: 15 Column: b

Environmental Cost Recovery	$ 5,218,913
Fuel Adjustment Clause KY	1,161,000
Amortization of Investment Tax Credit	2,686,401

Total	$ 9,066,314
	==========

Schedule Page: 261 Line No.: 20 Column: b

Federal Income Taxes:	
Utility Operating Income	$ 6,941,452
Other Income and Deductions	921,896
Tax over Book Depreciation, Net	264,026,573
Cost of Removal	16,792,475
Postretirement	1,204,658
Demand Side Management	2,185,387
Current State Income Tax	4,517,411
Mark-to-Market	208,723
Management Audit Fees	140,906
Bad Debt Reserve	149,521
EEI Investment	1,923,199

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Life Insurance	1,979,269
IRC 199 Manufacturing Deduction	446,629
Other	301,060

Total without Purchase Accounting	$301,739,159
Purchase Accounting Adjustments:	
FMV Bonds	66,306

Total	$301,805,465
	===========

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	Federal:					
2	Income	12,876,014		-4,628,293	8,247,721	
3	FICA	639,011		6,015,387	6,100,232	
4						
5	Kentucky:					
6	Income	2,021,179		6,170,840	8,192,019	
7	Public Service Commission		945,956	1,954,633	2,017,354	
8	Sales & Use	581,660		4,583,041	4,577,464	
9	Vehicle License			125,616	125,616	
10						
11	Federal & Kentucky:					
12	Unemployment Insurance	75,728		130,701	135,464	
13						
14	Kentucky & Indiana:					
15	Property Taxes	8,431,457		18,707,998	17,611,619	
16	Vehicle Tax					
17	Miscellaneous	-10,266				
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	24,614,783	945,956	33,059,923	47,007,489	

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
		-6,941,452			2,313,159	2
554,166		7,182,238			-1,166,851	3
						4
						5
		4,455,179			1,715,661	6
	1,008,677	1,954,633				7
587,237					4,583,041	8
		54,167			71,449	9
						10
						11
70,965		184,481			-53,780	12
						13
						14
9,527,836		18,703,289			4,709	15
						16
-10,266		36,958			-36,958	17
						18
						19
						20
						21
						22
						23
						24
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						40
10,729,938	1,008,677	25,629,493			7,430,430	41

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Schedule Page: 262 Line No.: 1 Column: a

Segregation of Other	Column L Other	Page 117 Other Inc & Deductions 408.2 – 409.2	Other Accounts
Federal:			
Income	$2,313,159	$(921,896)	$3,235,055
FICA	(1,166,851)		(1,166,851)
Kentucky:			
Income	1,715,661	(252,272)	1,967,933
6% Use (Kentucky)	4,583,041		4,583,041
Vehicle License	71,449		71,449
Federal & Kentucky:			
Unemployment Ins	(53,780)		(53,780)
Kentucky & Indiana:			
Property Taxes	4,709	2,004	2,705
Federal, State & Local:			
Vehicle Tax			
Miscellaneous	(36,958)		(36,958)
Total	$7,430,430	$(1,172,164)	$8,602,594

Reconciliation to page 114, line 14:

Other:	
Electric Total	$25,629,493
Less Federal	6,941,452
Less State	(4,455,179)
Total	$28,115,766

Schedule Page: 262 Line No.: 2 Column: g

End of the Year balance of $3,235,054 was reclassified to Accounts Receivable (143).

Schedule Page: 262 Line No.: 6 Column: g

End of the Year balance of $1,433,384 was reclassified to Accounts Receivable (143).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6		2,844,169			420	71,098	
7	15%	101,250,000			420	2,615,303	
8	TOTAL	104,094,169				2,686,401	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
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47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
2,773,071	41 years		6
98,634,697	37 years		7
101,407,768			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
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			48

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Brown CT Long-Term Service					
2	Agreement	7,302,453	151/657.27	1,178,748	151,657	6,275,362
3						
4	Coal Contracts					
5	(Nov-10 to Dec-15)	17,877,232	182.3	11,735,750		6,141,482
6						
7	Corporate Headquarters Lease					
8	(Nov-10 to Jul-15)	869,338	182.3	189,673		679,665
9						
10	Unearned Revenue -					
11	Pole Attachments	384,210			7,245	391,455
12						
13	Deferred Compensation	134,829			4,448	139,277
14						
15	Carrollton Sale/Leaseback					
16	(Aug-06 to Jul-23)	55,128	421.1	4,381		50,747
17						
18	Deferred Rent Payable					
19	(Aug-06 to Jul-23)	37,482			8,486	45,968
20						
21	Uncertain Tax Position - State	486,883	409.1	486,883	36,000	36,000
22						
23	Uncertain Tax Positions - Interest	90,458	431	90,458	6,792	6,792
24						
25						
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46						
47	TOTAL	27,238,013		13,685,893	214,628	13,766,748

Schedule Page: 269 Line No.: 5 Column: f

The balance of $6,141,482 relates to the fair value measurement of $22,605,479 for Kentucky Utilities Company's coal contracts that was recognized as a result of the acquisition by PPL Corporation in November 2010. The variance is 14 months of amortization in 2010 and 2011.

Schedule Page: 269 Line No.: 8 Column: f

The balance of $679,665 relates to the revaluation of $900,950 for the Kentucky Utilities Company's rent commitment for the Corporation Headquarters building that was recognized as a result of the acquisition by PPL Corporation in November 2010. The variance is 14 months of amortization in 2010 and 2011.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	346,844,638	205,798,250	94,684,070
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	346,844,638	205,798,250	94,684,070
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	346,844,638	205,798,250	94,684,070
10	Classification of TOTAL			
11	Federal Income Tax	300,449,376	181,906,814	80,944,591
12	State Income Tax	46,395,262	23,891,436	13,739,479
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		182/254	6,673,922	182/254/190	44,339,793	495,624,689	2
							3
							4
			6,673,922		44,339,793	495,624,689	5
							6
							7
							8
			6,673,922		44,339,793	495,624,689	9
							10
			6,024,274		37,784,428	433,171,753	11
			649,648		6,555,365	62,452,936	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Regulatory Tax Adjustments	5,288,580		
4	Loss on Reacquired Debt	4,840,363	14,027	273,869
5	MISO Exit Fees	1,743,980	39,112	763,610
6	FAC Over/Under-Recovery	7,005,162	3,571,522	20,465,461
7	Casualty Loss - Storm Damages	22,041,771	2,590,293	2,630,339
8	Other	91,794,177	4,247,133	29,153,309
9	TOTAL Electric (Total of lines 3 thru 8)	132,714,033	10,462,087	53,286,588
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	5,578,948		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	138,292,981	10,462,087	53,286,588
20	Classification of TOTAL			
21	Federal Income Tax	116,962,447	9,258,969	45,615,181
22	State Income Tax	21,330,534	1,203,118	7,671,407
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		182	2,526,194	182	26,495,220	29,257,606	3
						4,580,521	4
						1,019,482	5
				190	9,117,000	-771,777	6
						22,001,725	7
		283	7,268,991	283	432,699	60,051,709	8
			9,795,185		36,044,919	116,139,266	9
							10
							11
							12
							13
							14
							15
							16
							17
1,118,046	1,948,651	219/283	778,959	219/283	7,319,693	11,289,077	18
1,118,046	1,948,651		10,574,144		43,364,612	127,428,343	19
							20
968,647	1,671,135		9,919,475		37,789,314	107,773,586	21
149,399	277,516		654,669		5,575,298	19,654,757	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 8 Column: b

The balance in Accumulated Deferred Income Taxes- Other (283) was adjusted due to the purchase of KU by PPL Corporation in November 2010. The following reflects the balance at December 31, 2010:

Beginning Balance:	
Rate Case Expenses	$ 883,846
Tax Book Gain/Loss	3,426,974
OMU & Other Emission Allowances	220,399

Total Without Purchase Accounting	4,531,219
Purchase Accounting Adjustments:	
Purchase Accounting Adjustment – power purchase contract	15,008,409
Amortization of purchase accounting adjustment – power purchase contract	(180,555)
Purchase Accounting Adjustment – emission allowances	3,601,785
Amortization of purchase accounting adjustment – emission allowances	(382,690)
Purchase Accounting Adjustment – coal supply contracts	56,373,833
Amortization of purchase accounting adjustment – coal supply contracts	(1,298,823)
Purchase Accounting Adjustment – regulatory asset for coal supply contracts	8,793,531
Amortization of purchase accounting adjustment – regulatory asset for coal supply contracts	(1,839,288)
Purchase Accounting Adjustment – power purchase contract	350,470
Purchase Accounting Adjustment – EEI investment	6,893,734
Amortization of purchase accounting adjustment – EEI investment	(57,448)

Total	$91,794,177

Schedule Page: 276 Line No.: 8 Column: c

The balance was adjusted due to the amortization of purchase accounting adjustments that arose from the purchase of KU by PPL in November 2010. The following reflects the activity during the year charged to 410.1:

Debit Change Account 410.1:	
Rate Case Expenses	$ 340,357
Tax Book Gain/Loss	2,644,999
OMU & Other Emission Allowances	2,437

Total Without Purchase Accounting	2,987,793
Purchase Accounting Adjustment:	
Amortization - power purchase contract	51,077
Amortization - emission allowances	121,207
Amortization - EEI investment	6
Amortization - coal supply contracts	835,952
Amortization - regulatory assset for coal	246,451
Amortization - rent commitment	4,647

Total	$4,247,133

Schedule Page: 276 Line No.: 8 Column: d

The balance was adjusted due to the amortization of purchase accounting adjustments that arose from the purchase of KU by PPL in November 2010. The following reflects the activity during the year charged to 411.1:

Credit Change Account 411.1:

Rate Case Expenses	$ 780,737
Tax Book Gain/Loss	3,737,978
OMU & Other Emission Allowances	47,608

Total Without Purchase Accounting	4,566,323
Purchase Accounting Adjustment:	
Amortization - power purchase contract	997,220
Amortization - emission allowances	2,366,415
Amortization - coal supply contracts	16,320,966
Amortization - regulatory assset for coal	4,811,658
Amortization - rent commitment	90,727

Total	$29,153,309

Schedule Page: 276 Line No.: 8 Column: h

Debit Adjustments:

Purchase Accounting Adjustments:	
Reclass - EEI investment	$7,268,991

Total Debit Adjustments	$7,268,991

Schedule Page: 276 Line No.: 8 Column: j

The balance was adjusted due to the purchase of KU by PPL in November 2010. The following reflects the purchase accounting adjustment:

Credit Adjustments:

Purchase Accounting Adjustments:	
Reclass - EEI investment	$ 432,699

Total Credit Adjustments	$ 432,699

Schedule Page: 276 Line No.: 8 Column: k

The balance in Accumulated Deferred Income Taxes- Other (283) was adjusted due to the purchase of KU by PPL Corporation in November 2010. The following reflects the balance at December 31, 2011:

Ending Balance:

Rate Case Expenses	$ 443,466
Tax Book Gain/Loss	2,333,995
OMU & Other Emission Allowances	175,228

Total Without Purchase Accounting	2,952,689
Purchase Accounting Adjustments:	
Purchase Accounting Adjustment – power purchase contract	15,008,409
2011 Amortization of purchase accounting adjustment – power purchase contract	(946,143)
2010 Amortization of purchase accounting adjustment – power purchase contract	(180,555)
Purchase Accounting Adjustment – emission allowances	3,601,785
2011 Amortization of purchase accounting adjustment – emission allowances	(2,245,208)
2010 Amortization of purchase accounting adjustment – emission allowances	(382,690)
Purchase Accounting Adjustment – coal supply contracts	56,373,833
2011 Amortization of purchase accounting adjustment – coal supply contracts	(15,485,014)
2010 Amortization of purchase accounting adjustment – coal supply contracts	(1,298,823)
Purchase Accounting Adjustment – regulatory asset for coal supply contracts	8,793,531
2011 Amortization of purchase accounting adjustment – regulatory asset for coal supply contracts	(4,565,207)

2010 Amortization of purchase accounting adjustment – regulatory asset for coal supply contracts	(1,839,288)
Purchase Accounting Adjustment – rent commitment	350,470
2011 Amortization of purchase accounting adjustment - rent commitment	(86,080)
Total	$60,051,709

Schedule Page: 276 Line No.: 18 Column: b

The balance in Accumulated Deferred Income Taxes- Other (283) was adjusted due to the purchase of KU by PPL Corporation in November 2010. The following reflects the balance at December 31, 2010:

Beginning Balance:	
EEI Investment	$5,614,203
FIN 48 Interest	(33,438)
OCI EEI Investment	(1,269,297)
Total Without Purchase Accounting	4,311,468
Purchase Accounting Adjustments:	
Purchase Accounting Adjustment – EEI investment	1,267,480
Total	$5,578,948

Schedule Page: 276 Line No.: 18 Column: e

The balance was adjusted due to the amortization of purchase accounting adjustments that arose from the purchase of KU by PPL in November 2010. The following reflects the activity during the year charged to 410.2

Debit Change Account 410.2:	
EEI Investment	$ 996,437
FIN 48 Interest	34,576
Total Without Purchase Accounting	1,031,013
Purchase Accounting Adjustment:	
Amortization - EEI investment	87,033
Total	$1,118,046

Schedule Page: 276 Line No.: 18 Column: f

The balance was adjusted due to the amortization of purchase accounting adjustments that arose from the purchase of KU by PPL in November 2010. The following reflects the activity during the year charged to 411.2:

Credit Change Account 411.2:	
EEI Investment	$ 248,314
FIN 48 Interest	1,138
Total Without Purchase Accounting	249,452
Purchase Accounting Adjustment:	
Amortization - EEI investment	1,699,199
Total	$1,948,651

Schedule Page: 276 Line No.: 18 Column: h

Debit Adjustments:	
OCI EEI Investment	$ 346,253
Total Without Purchase Accounting	346,253

Purchase Accounting Adjustments:	
Reclass - EEI investment	432,706

Total Debit Adjustments	$ 778,959

Schedule Page: 276 Line No.: 18 Column: j

Credit Adjustments:	
OCI EEI Investment	$ 50,702

Total Without Purchase Accounting	50,702
Purchase Accounting Adjustments:	
Reclass - EEI investment	7,268,991

Total Credit Adjustments	$7,319,693

Schedule Page: 276 Line No.: 18 Column: k

The balance in Accumulated Deferred Income Taxes- Other (283) was adjusted due to the purchase of KU by PPL Corporation in November 2010. The following reflects the balance at December 31, 2011:

Ending Balance:	
EEI Investment	$ 6,362,326
FIN 48 Interest	-
OCI EEI Investment	(1,564,848)

Total Without Purchase Accounting	4,797,478
Purchase Accounting Adjustments:	
Purchase Accounting Adjustment – EEI investment	8,161,214
2011 Amortization of purchase accounting adjustment – EEI investment	(344,678)
2010 Amortization of purchase accounting adjustment – EEI investment	(57,448)
Eliminate Deferred Tax on Purchase Accounting Adjustment - Other Comprehensive Income	(1,267,489)

Total	$11,289,077

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Coal Contracts (Nov-10 to Dec-16)	141,581,000	186	41,621,407	1,814,173	101,773,766
2	ASC 740 - Income Taxes	19,784,136	190/282	966,701	63,974,347	82,791,782
3	OVEC Power Purchase Contract (Nov-10 to Mar-26)	38,117,876	186	2,432,244		35,685,632
4	ASC 715 - Pension and Postretirement	9,787,090	228.3	920,839		8,866,251
5	Environmental Cost Recovery	11,930,932	440-445	12,843,344	7,624,431	6,712,019
6	Asset Retirement Obligation	4,381,036	108	1,097,241	249,803	3,533,598
7	Emission Allowances (Nov-10 to Dec-40)	8,275,310	186	5,771,743		2,503,567
8	DSM Cost Recovery	4,503,512	440-445	5,693,598	3,508,210	2,318,124
9			182/184/502/			
10	Spare Parts	1,943,303	506/510-514	841,279	982,679	2,084,703
11			143/			
12	MISO Exit Fee Refund	637,621	182.3/575.7	65,310	450,868	1,023,179
13	KY Fuel Adjustment Clause	2,145,000	440-445	4,467,000	3,306,000	984,000
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41	TOTAL	243,086,816		76,720,706	81,910,511	248,276,621

Schedule Page: 278 Line No.: 1 Column: f

The balance in Coal Contracts (Nov-10 to Dec-16) relates to the regulatory offset for the fair value measurement of KU's coal contracts recognized due to the purchase of KU by PPL in November 2010. The balance will be amortized as the underlying purchase accounting adjustments are amortized. The following reflects the purchase accounting adjustment:

Coal Contracts (Nov-10 to Dec-16) Without Purchase Accounting	$ -
Purchase Accounting Adjustment	144,919,879
2011 Amortization of Purchase Accounting Adjustment	(39,807,234)
2010 Amortization of Purchase Accounting Adjustment	(3,338,879)
Total for Coal Contracts (Nov-10 to Dec-16)	$ 101,773,766

Schedule Page: 278 Line No.: 2 Column: f

The regulatory liabilities represent the future revenue impact from the reversal of deferred income taxes required for amortization investment tax credits and deferred taxes provided at rates in excess of currently enacted rates.

Schedule Page: 278 Line No.: 3 Column: f

The balance in OVEC Power Purchase Contract (Nov-10 to Mar-26) relates to the regulatory offset for the fair value measurement of the power purchase contract between KU and Ohio Valley Electric Corporation recognized due to the purchase of KU by PPL in November 2010. The balance will be amortized as the underlying purchase accounting adjustments are amortized. The following reflects the purchase accounting adjustment:

OVEC Power Purchase Contract (Nov-10 to Mar-26) Without Purchase Accounting	$ -
Purchase Accounting Adjustment	38,582,028
2011 Amortization of Purchase Accounting Adjustment	(2,432,244)
2010 Amortization of Purchase Accounting Adjustment	(464,152)
Total for OVEC Power Purchase Contract (Nov-10 to Mar-26)	$ 35,685,632

Schedule Page: 278 Line No.: 7 Column: f

The balance in Emission Allowances (Nov-10 to Dec-40) relates to the regulatory offset for the fair value measurement of KU's emission allowances recognized due to the purchase of KU by PPL in November 2010. The balance will be amortized as the underlying purchase accounting adjustments are amortized. The following reflects the purchase accounting adjustment:

Emission Allowances (Nov-10 to Dec-40) Without Purchase Accounting	$ -
Purchase Accounting Adjustment	9,259,090
2011 Amortization of Purchase Accounting Adjustment	(5,771,743)
2010 Amortization of Purchase Accounting Adjustment	(983,780)
Total for Emission Allowances (Nov-10 to Dec-40)	$ 2,503,567

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	525,604,627	545,709,127
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	346,999,690	342,592,061
5	Large (or Ind.) (See Instr. 4)	381,329,627	362,330,512
6	(444) Public Street and Highway Lighting	11,147,170	10,907,521
7	(445) Other Sales to Public Authorities	115,557,143	109,603,458
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,380,638,257	1,371,142,679
11	(447) Sales for Resale	140,153,792	117,277,200
12	TOTAL Sales of Electricity	1,520,792,049	1,488,419,879
13	(Less) (449.1) Provision for Rate Refunds		632,384
14	TOTAL Revenues Net of Prov. for Refunds	1,520,792,049	1,487,787,495
15	Other Operating Revenues		
16	(450) Forfeited Discounts	7,669,710	10,084,782
17	(451) Miscellaneous Service Revenues	2,470,663	2,309,143
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,856,543	990,054
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	368,937	1,364,815
22	(456.1) Revenues from Transmission of Electricity of Others	14,359,084	9,173,423
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	26,724,937	23,922,217
27	TOTAL Electric Operating Revenues	1,547,516,986	1,511,709,712

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
6,549,421	7,181,625	446,043	447,809	2
				3
4,306,626	4,570,183	83,794	84,851	4
6,698,135	6,458,351	2,353	2,244	5
50,815	55,934	1,266	1,418	6
1,651,441	1,669,816	7,383	7,963	7
				8
				9
19,256,438	19,935,909	540,839	544,285	10
3,125,213	2,446,009	28	22	11
22,381,651	22,381,918	540,867	544,307	12
				13
22,381,651	22,381,918	540,867	544,307	14

Line 12, column (b) includes $ -7,055,149 of unbilled revenues.

Line 12, column (d) includes -206,884 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 4 Column: b

Small (or Comm.) category includes Small and Large Commercial accounts.

Small	$ 183,822,247
Large	163,177,443
Total Small (or Comm.)	$ 346,999,690

Schedule Page: 300 Line No.: 4 Column: d

Small (or Comm.) category includes Small and Large Commercial accounts.

Small	2,018,962
Large	2,287,664
Total Small (or Comm.)	4,306,626 MWH

Schedule Page: 300 Line No.: 5 Column: b

Large (or Ind.) category includes Industrial and Mine Power accounts.

Industrial	$ 336,499,213
Mine Power	44,830,414
Total Large (or Industrial)	$ 381,329,627

Schedule Page: 300 Line No.: 5 Column: d

Large (or Ind.) category includes Industrial and Mine Power accounts.

Industrial	6,013,408
Mine Power	684,727
Total Large (or Industrial)	6,698,135 MWH

Schedule Page: 300 Line No.: 7 Column: b

Other Sales to Public Authorities category includes Other Sales to Public Authorities and Municipal Pumping accounts.

Other Sales to Public Authorities	$ 110,685,323
Municipal Pumping	4,871,820
Total Other Sales to Public Authorities	$ 115,557,143

Schedule Page: 300 Line No.: 7 Column: d

Other Sales to Public Authorities category includes Other Sales to Public Authorities and Municipal Pumping accounts.

Other Sales to Public Authorities	1,584,237
Municipal Pumping	67,204
Total Other Sales to Public Authorities	1,651,441 MWH

Schedule Page: 300 Line No.: 22 Column: b

Items which compose Revenues from Transmission of Electricity of Others (456.1) year-to-date activity:

2011 invoices to East Kentucky Power Cooperative	$ 3,409,283
2011 invoices to Owensboro Municipal Utilities	3,293,119
2011 invoices to Louisville Gas and Electric	3,266,566
2011 invoices to City of Frankfort	1,044,276
2011 invoices to Tennessee Valley Authority	663,758
2011 invoices to City of Madisonville	447,900
2011 invoices to City of Bardstown	336,057
2011 invoices to City of Nicholasville	289,653
2011 invoices to Cargill Power Markets	270,129

2011 invoices to Kentucky Municipal Power Agency		253,167
Other items less than $250,000 each		1,085,176
Total Other Electric Revenues	$	14,359,084

Schedule Page: 300 Line No.: 1 Column: $

This value contains unbilled revenue of $(15,371,557) and accrued revenue of $8,316,408. The accrued revenue represents the following:

Levelized Fuel Factor Accrual	$	(1,001,000)
Fuel Adjustment Clause Accrual		1,161,000
Demand Side Management Accrual		2,937,495
Environmental Cost Recovery Accrual		5,218,913
Total Accrual	$	8,316,408

Schedule Page: 300 Line No.: 1 Column: MWH

Unbilled revenue of (206,884) Mwh represents the net change of unbilled MWH from the previous period, and as a result could be positive or negative.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 440					
2	Residential Service - Ky	6,261,723	495,010,844	419,050	14,943	0.0791
3	General Service - Ky	657	65,882	978	672	0.1003
4	Volunteer Fire Department - Ky	105	8,347	7	15,000	0.0795
5	Outdoor Lighting - Ky	23,734	4,173,553	41,766	568	0.1758
6	Residential Service - Tn	104	5,191	5	20,800	0.0499
7	Outdoor Lighting - Tn	2	219	3	667	0.1095
8	Residential Service - Va	415,158	32,641,634	24,595	16,880	0.0786
9	General Service - Va	38	4,516	221	172	0.1188
10	Outdoor Lighting - Va	3,431	696,864	4,588	748	0.2031
11	Duplicate Customers			-45,170		
12						
13	Reclassifications and Adjustments	342	17,355			0.0507
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37						
38	Subtotal	6,705,294	532,624,405	446,043	15,033	0.0794
39	Unbilled	-155,873	-7,019,778			0.0450
40	Total	6,549,421	525,604,627	446,043	14,683	0.0803
41	TOTAL Billed	19,463,321	1,387,693,406	540,839	35,987	0.0713
42	Total Unbilled Rev.(See Instr. 6)	-206,883	-7,055,149	0	0	0.0341
43	TOTAL	19,256,438	1,380,638,257	540,839	35,605	0.0717

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 442					
2	Residential Service - Ky	518	40,593	241	2,149	0.0784
3	Volunteer Fire Department - Ky	22	1,696	1	22,000	0.0771
4	General Service - Ky	1,831,020	168,865,676	74,253	24,659	0.0922
5	All Electric School - Ky	16,821	1,193,820	114	147,553	0.0710
6	Time-of-Day Secondary - Ky	436,516	27,767,854	107	4,079,589	0.0636
7	Combined Lighting & Power - Ky	47,325	7,244,227	24,713	1,915	0.1531
8	Time-of-Day Primary - Ky	2,940,554	166,896,485	130	22,619,646	0.0568
9	Traffic Energy Service - Ky	331	31,937	250	1,324	0.0965
10	Power Service - Ky	3,227,514	224,893,405	5,099	632,970	0.0697
11	Fluctuating Load Service - Ky	538,943	26,182,350	2	269,471,500	0.0486
12	Retail Transmission Service - Ky	1,581,534	73,348,196	34	46,515,706	0.0464
13	Residential Service - Va	144	11,448	53	2,717	0.0795
14	General Service - Va	86,511	8,164,918	3,452	25,061	0.0944
15	Combined Lighting & Power - Va	1,240	255,540	798	1,554	0.2061
16	Power Service - Va	147,622	10,744,263	185	797,957	0.0728
17	Time-of-Day - Va	43,216	3,124,260	4	10,804,000	0.0723
18	School Service - Va	1,111	85,192	5	222,200	0.0767
19	Transmission Services - Va	172,433	11,006,986	11	15,675,727	0.0638
20	Duplicate Customers			-23,305		
21						
22	Reclassifications and Adjustments	2	-92,311			-46.1555
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38	Subtotal	11,073,377	729,766,535	86,147	128,540	0.0659
39	Unbilled	-68,616	-1,437,218			0.0209
40	Total	11,004,761	728,329,317	86,147	127,744	0.0662
41	TOTAL Billed	19,463,321	1,387,693,406	540,839	35,987	0.0713
42	Total Unbilled Rev.(See Instr. 6)	-206,883	-7,055,149	0	0	0.0341
43	TOTAL	19,256,438	1,380,638,257	540,839	35,605	0.0717

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 444					
2	Residential Service - Ky	44	3,501			0.0796
3	General Service - Ky	2,849	330,359	568	5,016	0.1160
4	Combined Power & Lighting - Ky	41,983	9,715,852	1,185	35,429	0.2314
5	Lighting Energy - Ky	28	1,583			0.0565
6	Power Service - Ky	1,180	90,932			0.0771
7	Traffic Energy Service - Ky	620	58,346	291	2,131	0.0941
8	General Service - Va	43	6,615	7	6,143	0.1538
9	Street Lighting - Va	1,617	323,486	72	22,458	0.2001
10	Duplicate Customers			-857		
11						
12	Reclassifications and Adjustments	-543	-54,646			0.1006
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38	Subtotal	47,821	10,476,028	1,266	37,773	0.2191
39	Unbilled	2,994	671,142			0.2242
40	Total	50,815	11,147,170	1,266	40,138	0.2194
41	TOTAL Billed	19,463,321	1,387,693,406	540,839	35,987	0.0713
42	Total Unbilled Rev.(See Instr. 6)	-206,883	-7,055,149	0	0	0.0341
43	TOTAL	19,256,438	1,380,638,257	540,839	35,605	0.0717

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 445					
2	Residential Service - Ky	2,726	236,572	368	7,408	0.0868
3	Volunteer Fire Department - Ky	846	64,758	36	23,500	0.0765
4	General Service - Ky	159,584	14,543,957	4,817	33,129	0.0911
5	All Electric School - Ky	144,067	10,120,692	515	279,742	0.0702
6	Power Service - Ky	734,995	53,125,596	1,083	678,666	0.0723
7	Combined Lighting & Power - Ky	10,307	1,842,091	2,786	3,700	0.1787
8	Time-of-Day Service Primary- Ky	483,305	27,371,060	8	60,413,125	0.0566
9	Time-of-Day Service Secondary- Ky	7,266	502,877	2	3,633,000	0.0692
10	Traffic Energy Service - Ky	111	9,716	40	2,775	0.0875
11	Retail Transmission Service- Ky	9,880	546,943	1	9,880,000	0.0554
12	Residential Service - Va	528	40,786	29	18,207	0.0772
13	General Service - Va	14,458	1,351,986	528	27,383	0.0935
14	School Service - Va	22,685	1,752,953	143	158,636	0.0773
15	Outdoor Lighting - Va	678	139,252	212	3,198	0.2054
16	Time of Day - Va	235	17,655			0.0751
17	Power Service - Va	44,213	3,104,722	35	1,263,229	0.0702
18	Municipal Water Pumping - Va	745	46,093	12	62,083	0.0619
19	Duplicate Customers			-3,232		
20						
21	Reclassifications and Adjustments	201	8,729			0.0434
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38	Subtotal	1,636,830	114,826,438	7,383	221,703	0.0702
39	Unbilled	14,611	730,705			0.0500
40	Total	1,651,441	115,557,143	7,383	223,682	0.0700
41	TOTAL Billed	19,463,321	1,387,693,406	540,839	35,987	0.0713
42	Total Unbilled Rev.(See Instr. 6)	-206,883	-7,055,149	0	0	0.0341
43	TOTAL	19,256,438	1,380,638,257	540,839	35,605	0.0717

Schedule Page: 304 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $2,488,260

Schedule Page: 304 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $(46)

Schedule Page: 304 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $31

Schedule Page: 304 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $8,833

Schedule Page: 304 Line No.: 11 Column: a
Average number of customers served under this rate schedule is 45,170 - included in revenue class subtotal. These are deducted on line 11 to avoid duplication.

Schedule Page: 304 Line No.: 13 Column: a
Reclassification between FERC accounts and net billing adjustments for prior periods.

Schedule Page: 304 Line No.: 13 Column: c
Includes Fuel Adjustment Clause of $(725)

Schedule Page: 304.1 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $103

Schedule Page: 304.1 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $23

Schedule Page: 304.1 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $957,778

Schedule Page: 304.1 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $7,550

Schedule Page: 304.1 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $240,191

Schedule Page: 304.1 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $20,515

Schedule Page: 304.1 Line No.: 8 Column: c
Includes Fuel Adjustment Clause of $1,761,950

Schedule Page: 304.1 Line No.: 9 Column: c
Includes Fuel Adjustment Clause of $204

Schedule Page: 304.1 Line No.: 10 Column: c
Includes Fuel Adjustment Clause of $1,790,228

Schedule Page: 304.1 Line No.: 11 Column: c
Includes Fuel Adjustment Clause of $337,540

Schedule Page: 304.1 Line No.: 12 Column: c
Includes Fuel Adjustment Clause of $927,063

Schedule Page: 304.1 Line No.: 20 Column: a
Average number of customers served under this rate schedule is 23,305 - included in revenue class subtotal. These are deducted on line 20 to avoid duplication.

Schedule Page: 304.1 Line No.: 22 Column: a
Reclassification between FERC accounts and net billing adjustments for prior periods.

Schedule Page: 304.1 Line No.: 22 Column: c
Includes Fuel Adjustment Clause of $574

Schedule Page: 304.2 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $6

Schedule Page: 304.2 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $802

Schedule Page: 304.2 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $15,448

Schedule Page: 304.2 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $29

Schedule Page: 304.2 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $(693)

Schedule Page: 304.2 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $351

Schedule Page: 304.2 Line No.: 10 Column: a
Average number of customers served under this rate schedule is 857 - included in revenue class subtotal. These are deducted on line 10 to avoid duplication.

Schedule Page: 304.2 Line No.: 12 Column: a
Reclassification between FERC accounts and net billing adjustments for prior periods.

Schedule Page: 304.2 Line No.: 12 Column: c
Includes Fuel Adjustment Clause of $1,020

Schedule Page: 304.3 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $1,127

Schedule Page: 304.3 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $228

Schedule Page: 304.3 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $78,083

Schedule Page: 304.3 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $71,231

Schedule Page: 304.3 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $400,062

Schedule Page: 304.3 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $5,605

Schedule Page: 304.3 Line No.: 8 Column: c
Includes Fuel Adjustment Clause of $392,689

Schedule Page: 304.3 Line No.: 9 Column: c
Includes Fuel Adjustment Clause of $5,406

Schedule Page: 304.3 Line No.: 10 Column: c
Includes Fuel Adjustment Clause of $45

Schedule Page: 304.3 Line No.: 11 Column: c
Includes Fuel Adjustment Clause of $(2,302)

Schedule Page: 304.3 Line No.: 19 Column: a
Average number of customers served under this rate schedule is 3,232 - included in revenue class subtotal. These are deducted on line 19 to avoid duplication.

Schedule Page: 304.3 Line No.: 21 Column: a
Reclassification between FERC accounts and net billing adjustments for prior periods.

Schedule Page: 304.3 Line No.: 21 Column: c
Includes Fuel Adjustment Clause of $(191)

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	City of Barbourville	RQ	184	19	19	18
2	City of Bardstown	RQ	185	32	32	32
3	City of Bardwell	RQ	186	2	2	2
4	City of Benham	RQ	187	2	2	1
5	City of Berea	RQ	197	24	25	24
6	City of Corbin	RQ	188	16	16	15
7	City of Falmouth	RQ	189	4	4	3
8	City of Frankfort	RQ	190	122	123	120
9	City of Madisonville	RQ	161	53	54	50
10	City of Nicholasville	RQ	157	34	34	33
11	City of Paris	RQ	83	11	11	11
12	City of Providence	RQ	195	6	6	6
13	Ameren Energy Marketing Company	OS	(3)	NA	NA	NA
14	American Electric Power Service Corp.	OS	(2)	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
105,288	2,467,067	417,953	2,898,123	5,783,143	1
198,806	4,412,689	797,331	5,468,455	10,678,475	2
9,103	232,156	36,506	251,665	520,327	3
6,658	215,544	26,680	183,451	425,675	4
134,115	3,238,747	532,300	3,690,250	7,461,297	5
86,412	2,128,131	343,020	2,382,976	4,854,127	6
19,869	560,574	79,685	548,140	1,188,399	7
714,672	16,318,300	2,836,970	19,660,270	38,815,540	8
326,890	7,332,212	1,310,961	9,007,615	17,650,788	9
209,255	4,531,032	830,608	5,747,321	11,108,961	10
61,241	1,446,480	71,654	1,855,785	3,373,919	11
33,558	808,973	134,594	925,973	1,869,540	12
108		4,898		4,898	13
2,193		91,638		91,638	14
1,905,867	43,691,905	7,418,262	52,620,024	103,730,191	
1,219,346	0	36,766,296	-342,695	36,423,601	
3,125,213	**43,691,905**	**44,184,558**	**52,277,329**	**140,153,792**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Associated Electric Coop Inc.	OS	(3)	NA	NA	NA
2	Bluegrass Generation Company LLC	OS	(4)	NA	NA	NA
3	BNP Paribas Energy Trading GP	OS	(3)	NA	NA	NA
4	Cargill Power Markets, LLC	OS	(3)	NA	NA	NA
5	Carolina Power and Light Company	OS	(3)	NA	NA	NA
6	Citigroup Energy Inc.	OS	(3)	NA	NA	NA
7	Constellation Energy Comm. Group, Inc.	OS	(3)	NA	NA	NA
8	East Kentucky Power Coop, Inc.	OS	(3)	NA	NA	NA
9	EDF Trading North America, LLC	OS	(3)	NA	NA	NA
10	Endure Energy, LLC	OS	(3)	NA	NA	NA
11	Illinois Municipal Electric Agency	OS	(5)	NA	NA	NA
12	Illinois Municipal Electric Agency	OS	(3)	NA	NA	NA
13	Indiana Municipal Power Agency	OS	(7)	NA	NA	NA
14	Indiana Municipal Power Agency	OS	(3)	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
33		1,319		1,319	1
21		2,100		2,100	2
14		589		589	3
3,327		140,727		140,727	4
8		623		623	5
22		880		880	6
103		7,850		7,850	7
1,390		60,872		60,872	8
430		18,982		18,982	9
892		40,381		40,381	10
46		3,122		3,122	11
331		33,181		33,181	12
413		26,309		26,309	13
389		38,879		38,879	14
1,905,867	43,691,905	7,418,262	52,620,024	103,730,191	
1,219,346	0	36,766,296	-342,695	36,423,601	
3,125,213	**43,691,905**	**44,184,558**	**52,277,329**	**140,153,792**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Kentucky Municipal Power Agency	OS	(6)	NA	NA	NA
2	Louisville Gas & Electric Company	SF	(1)	NA	NA	NA
3	Merrill Lynch Commodities, Inc.	OS	(3)	NA	NA	NA
4	MF Global Holding Ltd.	OS	NA	NA	NA	NA
5	Midwest Independent Transm. System Oper	OS	(3)	NA	NA	NA
6	Newedge USA LLC	OS	NA	NA	NA	NA
7	Owensboro Municipal Utilities	OS	(8)	NA	NA	NA
8	Owensboro Municipal Utilities	OS	(6)	NA	NA	NA
9	Owensboro Municipal Utilities	OS	(6)	NA	NA	NA
10	PJM Settlement, Inc.	OS	(3)	NA	NA	NA
11	PJM Settlement, Inc.	OS	(3)	NA	NA	NA
12	Rainbow Energy Marketing Corp.	OS	(3)	NA	NA	NA
13	Tenaska Power Services Company	OS	(3)	NA	NA	NA
14	Tennessee Valley Authority	OS	(3)	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
187		9,803		9,803	1
1,120,336		32,401,993		32,401,993	2
78		3,440		3,440	3
			-345,882	-345,882	4
4,455		250,357		250,357	5
			3,187	3,187	6
37		1,442		1,442	7
195		9,643		9,643	8
					9
69,105		2,932,843		2,932,843	10
					11
34		1,547		1,547	12
2,744		118,497		118,497	13
10,717		485,238		485,238	14
1,905,867	43,691,905	7,418,262	52,620,024	103,730,191	
1,219,346	0	36,766,296	-342,695	36,423,601	
3,125,213	**43,691,905**	**44,184,558**	**52,277,329**	**140,153,792**	

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	The Energy Authority, Inc.	OS	(3)	NA	NA	NA
2	Trademark Merchant Energy, LLC	OS	(3)	NA	NA	NA
3	Union Electric Co. (d/b/a Ameren MO)	OS	(3)	NA	NA	NA
4	Westar Energy, Inc.	OS	(3)	NA	NA	NA
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
905		37,051		37,051	1
216		14,094		14,094	2
53		2,121		2,121	3
564		25,877		25,877	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
1,905,867	43,691,905	7,418,262	52,620,024	103,730,191	
1,219,346	0	36,766,296	-342,695	36,423,601	
3,125,213	**43,691,905**	**44,184,558**	**52,277,329**	**140,153,792**	

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2011/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 Column: c
Barbourville Rate Schedule FERC No. 184 effective May 2009.

Schedule Page: 310 Line No.: 1 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 2 Column: c
Bardstown Rate Schedule FERC No. 185 effective May 2009.

Schedule Page: 310 Line No.: 2 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 3 Column: c
Bardwell Rate Schedule FERC No. 186 effective May 2009.

Schedule Page: 310 Line No.: 3 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 4 Column: c
Benham Rate Schedule FERC No. 187 effective May 2009.

Schedule Page: 310 Line No.: 4 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 5 Column: c
Berea Rate Schedule FERC No. 197 effective May 2009.

Schedule Page: 310 Line No.: 5 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 6 Column: c
Corbin Rate Schedule FERC No. 188 effective May 2009.

Schedule Page: 310 Line No.: 6 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 7 Column: c
Falmouth Rate Schedule FERC No. 189 effective May 2009.

Schedule Page: 310 Line No.: 7 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 8 Column: c
Frankfort Rate Schedule FERC No. 190 effective May 2009.

Schedule Page: 310 Line No.: 8 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 9 Column: c
Madisonville Rate Schedule FERC No. 161 effective May 2009.

Schedule Page: 310 Line No.: 9 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 10 Column: c
Nicholasville Rate Schedule FERC No. 157 effective May 2009.

Schedule Page: 310 Line No.: 10 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 11 Column: c
Paris Rate Schedule FERC No. 83 effective May 2009.

Schedule Page: 310 Line No.: 11 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 12 Column: c

Providence Rate Schedule FERC No. 195 effective May 2009.

Schedule Page: 310 Line No.: 12 Column: j

All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 13 Column: b

Market Based Sale

Schedule Page: 310 Line No.: 13 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310 Line No.: 14 Column: b

Market Based Sale

Schedule Page: 310 Line No.: 14 Column: c

(2) LGE and KU Joint MBRT Tariff.

Schedule Page: 310.1 Line No.: 1 Column: b

Market Based Sale

Schedule Page: 310.1 Line No.: 1 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.1 Line No.: 2 Column: b

Energy Imbalance

Schedule Page: 310.1 Line No.: 2 Column: c

(4) FERC Electric Tariff, Original No. 2, Service Agreement No. 255.

Schedule Page: 310.1 Line No.: 3 Column: b

Market Based Sale

Schedule Page: 310.1 Line No.: 3 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.1 Line No.: 4 Column: b

Market Based Sale

Schedule Page: 310.1 Line No.: 4 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.1 Line No.: 5 Column: a

d/b/a Progress Energy Carolinas Inc.

Schedule Page: 310.1 Line No.: 5 Column: b

Market Based Sale

Schedule Page: 310.1 Line No.: 5 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.1 Line No.: 6 Column: b

Market Based Sale

Schedule Page: 310.1 Line No.: 6 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.1 Line No.: 7 Column: b

Market Based Sale

Schedule Page: 310.1 Line No.: 7 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.1 Line No.: 8 Column: b

Market Based Sale

Schedule Page: 310.1 Line No.: 8 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.1 Line No.: 9 Column: b

Market Based Sale

Schedule Page: 310.1 Line No.: 9 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.1 Line No.: 10 Column: b

Market Based Sale

Schedule Page: 310.1 Line No.: 10 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.1 Line No.: 11 Column: b
Cost Based Sale

Schedule Page: 310.1 Line No.: 11 Column: c
(5) LGE CBR Tariff First Revised Service Agreement No. 3.

Schedule Page: 310.1 Line No.: 12 Column: b
Energy Imbalance

Schedule Page: 310.1 Line No.: 12 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.1 Line No.: 13 Column: b
Cost Based Sale

Schedule Page: 310.1 Line No.: 13 Column: c
(7) LGE CBR Tariff Service Agreement No. 4.

Schedule Page: 310.1 Line No.: 14 Column: b
Energy Imbalance

Schedule Page: 310.1 Line No.: 14 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.2 Line No.: 1 Column: b
Energy Imbalance

Schedule Page: 310.2 Line No.: 1 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4.

Schedule Page: 310.2 Line No.: 2 Column: a
Kentucky Utilities Company and Louisville Gas and Electric Company are owned by PPL Corporation.

Schedule Page: 310.2 Line No.: 2 Column: c
(1) FERC Rate Schedule No. 1. The Power Supply System Agreement, FERC Docket No. ER98-111-000.

Schedule Page: 310.2 Line No.: 3 Column: b
Market Based Sale

Schedule Page: 310.2 Line No.: 3 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.2 Line No.: 4 Column: b
Financial Swap

Schedule Page: 310.2 Line No.: 4 Column: j
Financial swap loss from unfavorable market conditions.

Schedule Page: 310.2 Line No.: 5 Column: b
Market Based Sale

Schedule Page: 310.2 Line No.: 5 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.2 Line No.: 6 Column: b
Financial Swap

Schedule Page: 310.2 Line No.: 7 Column: b
Cost Based Sale

Schedule Page: 310.2 Line No.: 7 Column: c
(8) LGE CBR Tariff.

Schedule Page: 310.2 Line No.: 8 Column: b
Energy Imbalance

Schedule Page: 310.2 Line No.: 8 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4.

Schedule Page: 310.2 Line No.: 9 Column: b
Energy Imbalance Sale of Test Power

Schedule Page: 310.2 Line No.: 9 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4.

Schedule Page: 310.2 Line No.: 9 Column: g
In May 2010, Trimble County 2 ("TC2"), a newly constructed generating unit, began producing test power. With limited exceptions, the Company took care, custody and control

of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. Prior to January 22, 2011, 35 MWH of test power was assigned to Kentucky Utilities Company's off-system sales to Owensboro Municipal Utilities that were credited to the capital project (Account 107) and are excluded from this report.

Schedule Page: 310.2 Line No.: 9 Column: i

In May 2010, Trimble County 2 ("TC2"), a newly constructed generating unit, began producing test power. With limited exceptions, the Company to care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. Prior to January 22, 2011, $1,972 of test power was assigned to Kentucky Utilities Company's off-system sales to Owensboro Municipal Utilities that were credited to the capital project (Account 107) and are excluded from this report.

Schedule Page: 310.2 Line No.: 10 Column: b

Market Based Sale

Schedule Page: 310.2 Line No.: 10 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.2 Line No.: 11 Column: b

Market Based Sale of Test Power

Schedule Page: 310.2 Line No.: 11 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.2 Line No.: 11 Column: g

In May 2010, Trimble County 2 ("TC2"), a newly constructed generating unit, began producing test power. With limited exceptions, the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. Prior to January 22, 2011, 5 MWH of test power was assigned to Kentucky Utilities Company's off-system sales to PJM Settlement, Inc. that were credited to the capital project (Account 107) and are excluded from this report.

Schedule Page: 310.2 Line No.: 11 Column: i

In May 2010, Trimble County 2 ("TC2"), a newly constructed generating unit, began producing test power. With limited exceptions, the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. Prior to January 22, 2011, $184 of test power was assigned to Kentucky Utilities Company's off-system sales to PJM Settlement, Inc. that were credited to the capital project (Account 107) and are excluded from this report.

Schedule Page: 310.2 Line No.: 12 Column: b

Market Based Sale

Schedule Page: 310.2 Line No.: 12 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.2 Line No.: 13 Column: b

Market Based Sale

Schedule Page: 310.2 Line No.: 13 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.2 Line No.: 14 Column: b

Market Based Sale

Schedule Page: 310.2 Line No.: 14 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.3 Line No.: 1 Column: b

Market Based Sale

Schedule Page: 310.3 Line No.: 1 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.3 Line No.: 2 Column: a

Effective September 6, 2011, Kansas City Energy changed its name to Trademark Merchant Energy, LLC.

Schedule Page: 310.3 Line No.: 2 Column: b

Market Based Sale

Schedule Page: 310.3 Line No.: 2 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2011/Q4

FOOTNOTE DATA

Schedule Page: 310.3 Line No.: 3 Column: b

Market Based Sale

Schedule Page: 310.3 Line No.: 3 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.3 Line No.: 4 Column: b

Market Based Sale

Schedule Page: 310.3 Line No.: 4 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	5,675,691	5,052,876
5	(501) Fuel	490,008,153	456,018,872
6	(502) Steam Expenses	18,117,669	15,369,118
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	7,028,116	6,019,436
10	(506) Miscellaneous Steam Power Expenses	24,491,050	18,657,073
11	(507) Rents	14,923	14,886
12	(509) Allowances	115,585	465,665
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	545,451,187	501,597,926
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	7,518,383	7,827,044
16	(511) Maintenance of Structures	6,215,716	5,750,632
17	(512) Maintenance of Boiler Plant	38,089,352	33,706,581
18	(513) Maintenance of Electric Plant	12,147,802	7,472,160
19	(514) Maintenance of Miscellaneous Steam Plant	2,376,947	2,338,458
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	66,348,200	57,094,875
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	611,799,387	558,692,801
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	7,598	7,910
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	57,700	42,443
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	65,298	50,353
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	113,239	104,647
54	(542) Maintenance of Structures	163,161	179,432
55	(543) Maintenance of Reservoirs, Dams, and Waterways	42,400	50,194
56	(544) Maintenance of Electric Plant	97,829	188,802
57	(545) Maintenance of Miscellaneous Hydraulic Plant	10,289	14,839
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	426,918	537,914
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	492,216	588,267

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	193,379	160,466
63	(547) Fuel	32,640,489	40,065,316
64	(548) Generation Expenses	323,470	293,562
65	(549) Miscellaneous Other Power Generation Expenses	131,803	126,894
66	(550) Rents	32,062	30,246
67	TOTAL Operation (Enter Total of lines 62 thru 66)	33,321,203	40,676,484
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	57,259	92,453
70	(552) Maintenance of Structures	304,697	411,346
71	(553) Maintenance of Generating and Electric Plant	1,976,711	3,909,806
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	449,694	788,094
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,788,361	5,201,699
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	36,109,564	45,878,183
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	109,114,948	174,621,937
77	(556) System Control and Load Dispatching	1,929,863	1,948,261
78	(557) Other Expenses	569,812	232,429
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	111,614,623	176,802,627
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	760,015,790	781,961,878
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,420,030	1,249,234
84	(561) Load Dispatching	1,901,369	1,465,344
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System		
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	135	772
89	(561.5) Reliability, Planning and Standards Development	756,221	730,443
90	(561.6) Transmission Service Studies	49,359	11,316
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	10	55
93	(562) Station Expenses	767,907	742,671
94	(563) Overhead Lines Expenses	466,728	403,446
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	2,476,360	3,520,121
97	(566) Miscellaneous Transmission Expenses	12,483,188	11,541,244
98	(567) Rents	97,338	138,597
99	TOTAL Operation (Enter Total of lines 83 thru 98)	20,418,645	19,803,243
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,948,538	1,374,877
108	(571) Maintenance of Overhead Lines	4,736,339	5,044,766
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	610,057	408,213
111	TOTAL Maintenance (Total of lines 101 thru 110)	7,294,934	6,827,856
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	27,713,579	26,631,099

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	1,412,238	1,883,682
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,412,238	1,883,682
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,412,238	1,883,682
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,495,447	1,679,744
135	(581) Load Dispatching	693,609	793,223
136	(582) Station Expenses	1,386,015	1,211,630
137	(583) Overhead Line Expenses	3,418,007	3,134,659
138	(584) Underground Line Expenses	265,333	275,541
139	(585) Street Lighting and Signal System Expenses	22,470	
140	(586) Meter Expenses	7,538,232	7,565,943
141	(587) Customer Installations Expenses	-79,639	-84,261
142	(588) Miscellaneous Expenses	5,124,964	5,079,901
143	(589) Rents	13,269	15,262
144	TOTAL Operation (Enter Total of lines 134 thru 143)	19,877,707	19,671,642
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	69,784	122,617
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	666,810	794,447
149	(593) Maintenance of Overhead Lines	26,227,833	24,778,802
150	(594) Maintenance of Underground Lines	479,392	651,909
151	(595) Maintenance of Line Transformers	127,331	84,192
152	(596) Maintenance of Street Lighting and Signal Systems		
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant	-1,103,830	-130,430
155	TOTAL Maintenance (Total of lines 146 thru 154)	26,467,320	26,301,537
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	46,345,027	45,973,179
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,722,056	2,527,610
160	(902) Meter Reading Expenses	4,836,309	4,513,214
161	(903) Customer Records and Collection Expenses	14,012,026	14,571,794
162	(904) Uncollectible Accounts	5,911,868	7,067,022
163	(905) Miscellaneous Customer Accounts Expenses	753,506	514,885
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	28,235,765	29,194,525

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	209,306	207,951
168	(908) Customer Assistance Expenses	13,127,928	11,521,815
169	(909) Informational and Instructional Expenses	155,032	174,962
170	(910) Miscellaneous Customer Service and Informational Expenses	308,037	376,752
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	13,800,303	12,281,480
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses	33,461	42,130
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	33,461	42,130
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	21,604,416	20,342,719
182	(921) Office Supplies and Expenses	7,356,115	7,105,951
183	(Less) (922) Administrative Expenses Transferred-Credit	2,610,773	1,624,418
184	(923) Outside Services Employed	8,618,092	6,856,825
185	(924) Property Insurance	4,205,919	4,682,557
186	(925) Injuries and Damages	3,080,346	2,451,761
187	(926) Employee Pensions and Benefits	40,898,849	39,239,991
188	(927) Franchise Requirements	3,596	3,186
189	(928) Regulatory Commission Expenses	1,866,287	1,123,535
190	(929) (Less) Duplicate Charges-Cr.	3,596	3,186
191	(930.1) General Advertising Expenses	795,814	558,382
192	(930.2) Miscellaneous General Expenses	2,963,630	2,381,131
193	(931) Rents	2,294,768	2,199,215
194	TOTAL Operation (Enter Total of lines 181 thru 193)	91,073,463	85,317,649
195	Maintenance		
196	(935) Maintenance of General Plant	12,977,636	11,850,104
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	104,051,099	97,167,753
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	981,607,262	995,135,726

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Schedule Page: 320 Line No.: 141 Column: b

The credit is due to meter tampering charges billed to customers to offset the cost of meter maintenance. The cost is recorded in several accounts.

Schedule Page: 320 Line No.: 141 Column: c

The credit is due to meter tampering charges billed to customers to offset the cost of meter maintenance. The cost is recorded in several accounts.

Schedule Page: 320 Line No.: 154 Column: b

The credit balance is due to establishing a regulatory asset for the 2009 mountain winter storm in Eastern Kentucky and Virginia.

Schedule Page: 320 Line No.: 154 Column: c

The credit balance is due to reversing an expense over-accrual of the 2009 mountain winter storm in Eastern Kentucky and Virginia.

Schedule Page: 320 Line No.: 193 Column: b

The balance in Rents (931) was adjusted due to the purchase of KU by PPL in November 2010. The balance was adjusted to include amortization of the purchase accounting adjustment related to the rent commitment for the Corporate Headquarters building. The rent commitment amortization inadvertently charged to Rents in 2010 was reclassified to Other Regulatory Liabilities (254) in January 2011. The following reflects the purchase accounting adjustment:

Rents (931) Without Purchase Accounting	$ 2,263,156
Purchase Accounting Adjustment - rent commitment	31,612
Total for Rents (931)	$ 2,294,768

Schedule Page: 320 Line No.: 193 Column: c

The balance in Rents (931) was adjusted due to the purchase of KU by PPL in November 2010. The balance was adjusted to include amortization of the purchase accounting adjustment related to the rent commitment for the Corporate Headquarters building. The rent commitment amortization inadvertently charged to Rents in 2010 was reclassified to Other Regulatory Liabilities (254) in January 2011. The following reflects the purchase accounting adjustment:

Rents (931) Without Purchase Accounting	$ 2,230,827
Purchase Accounting Adjustment - rent commitment	(31,612)
Total for Rents (931)	$ 2,199,215

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Ameren Energy Marketing Company	OS	(1)	NA	NA	NA
2	American Electric Power Service Corp.	OS	(1)	NA	NA	NA
3	Associated Electric Coop Inc	OS	(7)	NA	NA	NA
4	Big Rivers Electric Corp.	OS	(12)	NA	NA	NA
5	Bluegrass Generation Company LLC	OS	(5)	NA	NA	NA
6	Cargill Power Markets, LLC	OS	(1)	NA	NA	NA
7	Constellation Energy Comm. Group Inc.	OS	(1)	NA	NA	NA
8	East Kentucky Power Coop. Inc.	OS	(11)	NA	NA	NA
9	East Kentucky Power Coop. Inc.	OS	(4)	NA	NA	NA
10	EDF Trading North America, LLC	OS	(1)	NA	NA	NA
11	Endure Energy, LLC	OS	(1)	NA	NA	NA
12	Illinois Municipal Electric Agency	OS	(8)	NA	NA	NA
13	Illinois Municipal Electric Agency	AD	(8)	NA	NA	NA
14	Indiana Municipal Power Agency	OS	(8)	NA	NA	NA
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
15,557				703,274		703,274	1
3,125				131,916		131,916	2
1,845				81,911		81,911	3
23				835		835	4
690				40,990		40,990	5
4,074				184,772		184,772	6
105				4,140		4,140	7
3,752				212,978		212,978	8
21				2,100		2,100	9
23,762				1,775,185		1,775,185	10
48				2,112		2,112	11
1,090				25,376		25,376	12
-8					-159	-159	13
35,735				884,645		884,645	14
4,188,345	199,226		8,194,423	100,928,538	-8,013	109,114,948	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Indiana Municipal Power Agency	AD	(8)	NA	NA	NA
2	Indiana Municipal Power Agency	OS	(8)	NA	NA	NA
3	Kentucky Municipal Power Agency	OS	(3)	NA	NA	NA
4	Louisville Gas & Electric Co.	SF	(2)	NA	NA	NA
5	Midwest Independent Transm. System Ope	OS	(1)	NA	NA	NA
6	Ohio Valley Electric Corporation	OS	(6)	NA	NA	NA
7	Ohio Valley Electric Corporation	AD	(6)	NA	NA	NA
8	Owensboro Municipal Utilities	OS	(9)	NA	NA	NA
9	Owensboro Municipal Utilities	OS	(3)	NA	NA	NA
10	Owensboro Municipal Utilities	AD	(13)	NA	NA	NA
11	PJM Settlement, Inc.	OS	(1)	NA	NA	NA
12	PJM Settlement, Inc.	AD	(1)	NA	NA	NA
13	Tenaska Power Services Company	OS	(1)	NA	NA	NA
14	Tennessee Valley Authority	OS	(10)	NA	NA	NA
	Total					

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					11,070	11,070	1
1,025				22,769		22,769	2
2,193				83,750		83,750	3
3,641,187				82,377,392		82,377,392	4
413				29,220		29,220	5
348,675			8,194,423	9,760,521		17,954,944	6
					-10,138	-10,138	7
972				32,976		32,976	8
3,506				113,847		113,847	9
					-8,481	-8,481	10
81,306				3,596,633		3,596,633	11
					-305	-305	12
84				3,192		3,192	13
8,914				388,449		388,449	14
4,188,345	199,226		8,194,423	100,928,538	-8,013	109,114,948	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Tennessee Valley Authority	OS	(4)	NA	NA	NA
2	The Energy Authority, Inc.	OS	(7)	NA	NA	NA
3	Union Electric Co. (d/b/a Ameren MO)	OS	(1)	NA	NA	NA
4	Westar Energy, Inc.	OS	(1)	NA	NA	NA
5	Inadvertent Interchange			NA	NA	NA
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
244				26,964		26,964	1
3,261				153,843		153,843	2
6,441				276,938		276,938	3
305				11,810		11,810	4
	199,226						5
							6
							7
							8
							9
							10
							11
							12
							13
							14
4,188,345	199,226		8,194,423	100,928,538	-8,013	109,114,948	

Schedule Page: 326 Line No.: 1 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 1 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 2 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 2 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 3 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 3 Column: c
(7) WSPP Rate Schedule FERC No. 6.
Schedule Page: 326 Line No.: 4 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 4 Column: c
(12) Rate Schedule 27
Schedule Page: 326 Line No.: 5 Column: b
Energy Imbalance
Schedule Page: 326 Line No.: 5 Column: c
(5) FERC Electric Tariff, Original Volume No. 2, Service Agreement No. 255.
Schedule Page: 326 Line No.: 6 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 6 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 7 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 7 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 8 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 8 Column: c
(11) EEI Master Power Purchase and Sale Agreement dated November 20, 2009.
Schedule Page: 326 Line No.: 9 Column: b
Emergency Power
Schedule Page: 326 Line No.: 9 Column: c
(4) TEE Contingency Reserve Sharing Agreement dated November 20, 2009.
Schedule Page: 326 Line No.: 10 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 10 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 11 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 11 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 12 Column: b
Energy Imbalance
Schedule Page: 326 Line No.: 12 Column: c
(8) Participation Agreement dated February 9, 2004.
Schedule Page: 326 Line No.: 13 Column: b
December 2010 true-up of accrual estimate for energy charges made in 2011.
Schedule Page: 326 Line No.: 13 Column: c
(8) Participation Agreement dated February 9, 2004.
Schedule Page: 326 Line No.: 13 Column: g
December 2010 true-up of accrual estimate for energy charges made in 2011.

Schedule Page: 326 Line No.: 13 Column: l
December 2010 true-up of accrual estimate for energy charges made in 2011.
Schedule Page: 326 Line No.: 14 Column: b
Cost Based Purchase
Schedule Page: 326 Line No.: 14 Column: c
(8) Participation Agreement dated February 9, 2004.
Schedule Page: 326.1 Line No.: 1 Column: b
November 2010 correction made in 2011.
Schedule Page: 326.1 Line No.: 1 Column: c
(8) Participation Agreement dated February 9, 2004.
Schedule Page: 326.1 Line No.: 1 Column: l
November 2010 correction made in 2011.
Schedule Page: 326.1 Line No.: 2 Column: b
Energy Imbalance
Schedule Page: 326.1 Line No.: 2 Column: c
(8) Participation Agreement dated February 9, 2004.
Schedule Page: 326.1 Line No.: 3 Column: b
Energy Imbalance
Schedule Page: 326.1 Line No.: 3 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4.
Schedule Page: 326.1 Line No.: 4 Column: a
Kentucky Utilities Company and Louisville Gas and Electric Company are owned by PPL Corporation.
Schedule Page: 326.1 Line No.: 4 Column: c
(2) FERC Rate Schedule No. 1. The Power Supply System Agreement, FERC Docket No. ER98-111-000
Schedule Page: 326.1 Line No.: 5 Column: b
Market Based Purchase
Schedule Page: 326.1 Line No.: 5 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326.1 Line No.: 6 Column: a
Inter-company Power Agreement dated September 10, 2010. The Company owns 2.5% of the common stock of Ohio Valley Electric Corporation (OVEC). Purchase of surplus power pursuant to Article 4 of the Amended and Restated Inter-company Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.
Schedule Page: 326.1 Line No.: 6 Column: b
Surplus Power
Schedule Page: 326.1 Line No.: 6 Column: c
(6) Purchase of surplus power pursuant to Article 4 of the Amended and Restated Inter-company Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.
Schedule Page: 326.1 Line No.: 7 Column: a
Inter-company Power Agreement dated September 10, 2010. The Company owns 2.5% of the common stock of Ohio Valley Electric Corporation (OVEC). Purchase of surplus power pursuant to Article 4 of the Amended and Restated Inter-company Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.
Schedule Page: 326.1 Line No.: 7 Column: b
December 2010 true-up of accrual estimate for both energy and demand charges made in 2011.
Schedule Page: 326.1 Line No.: 7 Column: c
(6) Purchase of surplus power pursuant to Article 4 of the Amended and Restated Inter-company Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.
Schedule Page: 326.1 Line No.: 7 Column: l
December 2010 true-up of accrual estimate for both energy, $47,176, and demand charges ($57,314) made in 2011.
Schedule Page: 326.1 Line No.: 8 Column: b

BLANK

Market Based Purchase

Schedule Page: 326.1 Line No.: 8 Column: c

(9) EEI Master Power Purchase and Sale Agreement dated April 27, 2011.

Schedule Page: 326.1 Line No.: 9 Column: b

Energy Imbalance

Schedule Page: 326.1 Line No.: 9 Column: c

(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4.

Schedule Page: 326.1 Line No.: 10 Column: b

Correction of 2010 demand charge made in 2011.

Schedule Page: 326.1 Line No.: 10 Column: c

(13) FERC Electric Tariff FPC 74

Schedule Page: 326.1 Line No.: 10 Column: l

Correction of 2010 demand charge made in 2011.

Schedule Page: 326.1 Line No.: 11 Column: b

Market Based Purchase

Schedule Page: 326.1 Line No.: 11 Column: c

(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.1 Line No.: 12 Column: b

December 2010 correction made in 2011.

Schedule Page: 326.1 Line No.: 12 Column: c

(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.1 Line No.: 12 Column: l

December 2010 correction made in 2011.

Schedule Page: 326.1 Line No.: 13 Column: b

Market Based Purchase

Schedule Page: 326.1 Line No.: 13 Column: c

(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.1 Line No.: 14 Column: b

Market Based Purchase

Schedule Page: 326.1 Line No.: 14 Column: c

(10) Interchange Agreement dated July 1, 1977.

Schedule Page: 326.2 Line No.: 1 Column: b

Emergency Power

Schedule Page: 326.2 Line No.: 1 Column: c

(4) TEE Contingency Reserve Sharing Agreement dated November 20, 2009.

Schedule Page: 326.2 Line No.: 2 Column: b

Market Based Purchase

Schedule Page: 326.2 Line No.: 2 Column: c

(7) WSPP Rate Schedule FERC No. 6.

Schedule Page: 326.2 Line No.: 3 Column: b

Market Based Purchase

Schedule Page: 326.2 Line No.: 3 Column: c

(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.2 Line No.: 4 Column: b

Market Based Purchase

Schedule Page: 326.2 Line No.: 4 Column: c

(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	FNO
2	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	AD
3	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	NF
4	Kentucky Municipal Power Agency	Midwest ISO	Kentucky Municipal Power Agency	FNO
5	Kentucky Municipal Power Agency	N/A	N/A	OS
6	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	FNO
7	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	LFP
8	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	SFP
9	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	NF
10	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	OLF
11	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
12	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	NF
13	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
14	Big Rivers Electric Corporation	Big Rivers Electric Corporation	Big Rivers Electric Corporation	FNO
15	KU/LG&E	Various	Various	NF
16	KU/LG&E	Various	Various	AD
17	KU/LG&E	Various	Various	SFP
18	KU/LG&E	Various	Various	LFP
19	The Energy Authority	Various	Various	NF
20	Ameren Energy Marketing	Various	Various	SFP
21	Cargill Power Markets, LLC	Various	Various	SFP
22	Cargill Power Markets, LLC	Various	Various	AD
23	Cargill Power Markets, LLC	Various	Various	NF
24	Constellation Energy Commodities Group	PJM	Tennessee Valley Authority	SFP
25	Constellation Energy Commodities Group	PJM	Tennessee Valley Authority	NF
26	City of Barbourville	Various	City of Barbourville	FNO
27	City of Bardstown	Various	City of Bardstown	FNO
28	City of Bardwell	Various	City of Bardwell	FNO
29	City of Benhem	Various	City of Benhem	FNO
30	City of Berea	Various	City of Berea	FNO
31	City of Corbin	Various	City of Corbin	FNO
32	City of Falmouth	Various	City of Falmouth	FNO
33	City of Frankfort	Various	City of Frankfort	FNO
34	City of Madisonville	Various	City of Madisonville	FNO
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
LGE/KU Joint	East Kentucky Power	East Kentucky Power	1,345	2,157,332	2,094,672	1
LGE/KU Joint	East Kentucky Power	East Kentucky Power				2
LGE/KU Joint	East Kentucky Power	East Kentucky Power				3
SA 13	Various	LGEE.KMPA	345	518,139	503,187	4
402	N/A	N/A				5
SA 15	Owensboro Municipal	Various	392	3,325		6
LGE/KU Joint	Owensboro Municipal	Various	182	1,240,654	1,199,318	7
LGE/KU Joint	Owensboro Municipal	Various	356			8
LGE/KU Joint	Owensboro Municipal	Various				9
SA 11	TVA	TVA	213	344,597	335,857	10
SA 11	TVA	TVA				11
LGE/KU Joint	TVA	TVA		214	214	12
LGE/KU Joint	TVA	TVA				13
LGE/KU Joint	Big Rivers Electric	Big Rivers Electric	15	25,801	25,050	14
LGE/KU Joint	Various	Various				15
LGE/KU Joint	Various	Various				16
LGE/KU Joint	Various	Various	414			17
LGE/KU Joint	Various	Various	356			18
LGE/KU Joint	Various	Various		88	87	19
LGE/KU Joint	Various	Various		20,172	19,561	20
LGE/KU Joint	Various	Various	24	92,373	89,668	21
LGE/KU Joint	Various	Various				22
LGE/KU Joint	Various	Various		139	136	23
LGE/KU Joint	PJM	TVA	59	96,572	93,344	24
LGE/KU Joint	PJM	TVA				25
184	Various	City of Barbourville	144			26
185	Various	City of Bardstown	311			27
186	Various	City of Bardwell	27			28
187	Various	City of Benham	40			29
197	Various	City of Berea	202			30
188	Various	City of Corbin	126			31
189	Various	City of Falmouth	47			32
190	Various	City of Frankfort	944			33
161	Various	City of Madisonville	404			34
			6,344	**4,499,406**	**4,361,094**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	City of Nicholasville	Various	City of Nicholasville	FNO
2	City of Paris	Various	City of Paris	FNO
3	City of Providence	Various	City of Providence	FNO
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
157	Various	City of Nicholasvill	262			1
83	Various	City of Paris	90			2
195	Various	City of Providence	46			3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
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						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			6,344	**4,499,406**	**4,361,094**	

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
3,235,002		176,978	3,411,980	1
8,607		422	9,029	2
	-3,816		-3,816	3
1,112,704		251,185	1,363,889	4
-1,046,599		-64,123	-1,110,722	5
896,921		255,868	1,152,789	6
561,357		28,888	590,245	7
1,064,384		53,344	1,117,728	8
70,175	346,118	16,065	432,358	9
595,129		28,368	623,497	10
33,180		3,419	36,599	11
	1,967	18	1,985	12
	1,678		1,678	13
50,724		2,544	53,268	14
	1,333,615	49,571	1,383,186	15
	23,103		23,103	16
1,489,666		68,185	1,557,851	17
1,145,385		57,955	1,203,340	18
	214	8	222	19
	46,797	1,909	48,706	20
75,069	179,237	11,697	266,003	21
	192		192	22
	3,745	189	3,934	23
164,986		7,760	172,746	24
	57	2	59	25
155,582		4,234	159,816	26
327,174		8,882	336,056	27
27,386		740	28,126	28
38,328		1,031	39,359	29
213,906		5,815	219,721	30
136,388		3,707	140,095	31
48,227		1,304	49,531	32
1,016,611		27,665	1,044,276	33
436,037		11,863	447,900	34
12,284,749	**1,932,907**	**1,027,150**	**15,244,806**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS				
Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
281,980		7,672	289,652	1
96,373		2,622	98,995	2
50,067		1,363	51,430	3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
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				21
				22
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				24
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				26
				27
				28
				29
				30
				31
				32
				33
				34
12,284,749	**1,932,907**	**1,027,150**	**15,244,806**	

Schedule Page: 328 Line No.: 1 Column: m
The total consists of East Kentucky Power Cooperative Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 2 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 2 Column: m
The total consists of a true-up of prior periods for East Kentucky Power Cooperative Schedule 1 and Schedule 2 charges related to firm transmission.

Schedule Page: 328 Line No.: 3 Column: l
The total consists of the amortization of a regulatory asset authorized by the settlement agreement between Kentucky Utilities Company, Louisville Gas and Electric Company and East Kentucky Power Cooperative regarding the Network Integration Transmission Service Agreement. FERC Docket Nos. ER06-1458-000, ER06-1458-001 and ER06-1458-002.

Schedule Page: 328 Line No.: 4 Column: m
The total consists of Kentucky Municipal Power Agency Schedule 1, Schedule 2, Schedule 3, Schedule 5, and Schedule 6 charges.

Schedule Page: 328 Line No.: 5 Column: k
The amount consists of Kentucky Municipal Power Agency depancaking credits related to Kentucky Utilities Company's exit from the MISO, pursuant to Rate Schedule 402 as filed with and accepted by the FERC.

Schedule Page: 328 Line No.: 5 Column: m
The total consists of Kentucky Municipal Power Agency Schedule 1 and Schedule 2 charges for depancaking credits related to Kentucky Utilities Company's exit from the MISO, pursuant to Rate Schedule 402 as filed with and accepted by the FERC.

Schedule Page: 328 Line No.: 6 Column: m
The total consists of Owensboro Municipal Utilities Schedule 1, Schedule 2, Schedule 3, Schedule 5 and Schedule 6 charges.

Schedule Page: 328 Line No.: 7 Column: m
The total consists of Owensboro Municipal Utilities Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 8 Column: m
The total consists of Owensboro Municipal Utilities Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 9 Column: m
The total consists of Owensboro Municipal Utilities Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 10 Column: d
The OLF transmission service agreement between Kentucky Utilities Company and Tennessee Valley Authority has a termination date of 12/31/2011.

Schedule Page: 328 Line No.: 10 Column: m
The total consists of Tennessee Valley Authority Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 11 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 11 Column: m
The total consists of a true-up of prior period Tennessee Valley Authority Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 12 Column: m
The total consists of Tennessee Valley Authority Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 13 Column: l
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 14 Column: m
The total consists of Big Rivers Electric Corporation Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 15 Column: a
Kentucky Utilities Company and Louisville Gas and Electric Company are owned by PPL Corporation.

Schedule Page: 328 Line No.: 15 Column: m
The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 16 Column: a
Kentucky Utilities Company and Louisville Gas and Electric Company are owned by PPL

Corporation.

Schedule Page: 328 Line No.: 16 Column: l

The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 17 Column: a

Kentucky Utilities Company and Louisville Gas and Electric Company are owned by PPL Corporation.

Schedule Page: 328 Line No.: 17 Column: m

The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 18 Column: a

Kentucky Utilities Company and Louisville Gas and Electric Company are owned by PPL Corporation.

Schedule Page: 328 Line No.: 18 Column: d

Long-term Firm purchases by Kentucky Utilities Company and Louisville Gas and Electric Company take place under the Open Access Transmission Tariff with intercompany allocations for revenues and expenses determined by the Transmission Coordination Agreement between the Companies. The Tariff is evergreen and the Transmission Coordination Agreement automatically renews unless terminated.

Schedule Page: 328 Line No.: 18 Column: m

The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 19 Column: m

The total consists of The Energy Authority Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 20 Column: m

The total consists of Ameren Marketing Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 21 Column: m

The total consists of Cargill Power Markets, LLC Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 22 Column: l

The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 23 Column: m

The total consists of Cargill Power Markets, LLC Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 24 Column: m

The total consists of Constellation Energy Commodities Group, Inc. Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 25 Column: m

The total consists of Constellation Energy Commodities Group, Inc. Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 26 Column: m

The total consists of City of Barbourville Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 27 Column: m

The total consists of City of Bardstown Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 28 Column: m

The total consists of City of Bardwell Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 29 Column: m

The total consists of City of Benham Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 30 Column: m

The total consists of City of Berea Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 31 Column: m

The total consists of City of Corbin Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 32 Column: m

The total consists of City of Falmouth Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 33 Column: m

The total consists of City of Frankfort Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 34 Column: m

The total consists of City of Madisonville Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 1 Column: m

The total consists of City of Nicholasville Schedule 1 and Schedule 2 charges.

BLANK

Schedule Page: 328.1 Line No.: 2 Column: m

The total consists of City of Paris Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 3 Column: m

The total consists of City of Providence Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 3 Column: n

This footnote is not to reference this cell, but the total on line 35 column (n).

The total amount does not agree to page 300, line 22, column (b) due to intracompany transmission revenues that must be eliminated in consolidation:

Page 330, line 35, column (n)	$ 15,244,806
Elimination of intracompany transmission revenues	(885,722)
Page 300, line 22, column (b)	$ 14,359,084

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Midwest ISO	NF					-1	-1
2	Midwest ISO	AD				13,430	1,458	14,888
3	East Kentucky Power	LFP			1,730,251		91,324	1,821,575
4	East Kentucky Power	AD			50,287		48,349	98,636
5	KU/LG&E	LFP	341,081	341,081	485,499		36,674	522,173
6	KU/LG&E	SFP	189,046	189,046	504,770		31,512	536,282
7	KU/LG&E	NF	70,821	70,821		229,796	12,589	242,385
8	PJM Interconnect	NF	46,244	46,244		50,401	68,110	118,511
9	PJM Interconnect	AD			-996	247	8,859	8,110
10	Tennessee Valley Auth	AD				-475		-475
11								
12								
13								
14								
15								
16								
	TOTAL		647,192	647,192	2,769,811	293,399	298,874	3,362,084

Schedule Page: 332 Line No.: 1 Column: g

The total consists of pass-through of a reduction in Schedule 26 expense for the period of January 2011 – March 2011.

Schedule Page: 332 Line No.: 2 Column: f

The total consists of true-ups of charges for prior periods.

Schedule Page: 332 Line No.: 2 Column: g

The total consists of a rate adjustment in Schedule 8 pass through expense for the period of June 2009 and a rate adjustment in Schedule 1 pass through expense for the period of January through May 2009 and July 2009.

Schedule Page: 332 Line No.: 3 Column: b

The LFP transmission service agreement between East Kentucky Power Cooperative and KU and LG&E has a termination date of 9/30/2016.

Schedule Page: 332 Line No.: 3 Column: g

The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 4 Column: e

The total consists of true-ups of charges for prior periods.

Schedule Page: 332 Line No.: 4 Column: g

The total consists of true-ups of Schedule 1 and Schedule 2 charges for prior periods.

Schedule Page: 332 Line No.: 5 Column: a

KU and LG&E are owned by PPL Corporation.

Schedule Page: 332 Line No.: 5 Column: b

Long-term Firm purchases by KU and LG&E take place under the Open Access Transmission Tariff with intercompany allocations for revenues and expenses determined by the Transmission Coordination Agreement between the Companies. The Tariff is evergreen and the Transmission Coordination Agreement automatically renews unless terminated.

Schedule Page: 332 Line No.: 5 Column: g

The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 6 Column: a

KU and LG&E are owned by PPL Corporation.

Schedule Page: 332 Line No.: 6 Column: g

The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 7 Column: a

KU and LG&E are owned by PPL Corporation.

Schedule Page: 332 Line No.: 7 Column: g

The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 8 Column: g

The total consists of Schedule 1, Schedule 2, Black Start service and charges for other non-firm point-to-point transmission without energy.

Schedule 1 Non-firm:	$ 28,807
Schedule 2 Non-firm:	18,453
Black Start Service Non-firm:	843
Non-firm point-to-point without energy:	20,007
	$ 68,110

Schedule Page: 332 Line No.: 9 Column: e

The total consists of true-ups of charges for prior periods.

Schedule Page: 332 Line No.: 9 Column: g

The total consists of true-ups of prior period Schedule 1, Schedule 2, Black Start service and charges for other non-firm point-to-point without energy.

Schedule 1 Non-firm:	$ 4,591
Schedule 2 Non-firm:	1,507
Black Start Service Non-firm:	(188)
Non-firm point-to-point without energy:	2,949

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	/ /	2011/Q4

FOOTNOTE DATA

$ 8,859

~~***Schedule Page: 332 Line No.: 10 Column: f***~~

The total consists of true-ups of charges for prior periods.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	441,955
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	2,244,608
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	45,766
6	Water Use Fees	101,607
7	Marketing Research and Consulting Fees	
8	Bellomy Research	62,422
9	Chartwell, Inc.	6,497
10	Datamentors LLC	5,025
11	Experian Marketing Solutions	34,605
12	Kforce Inc.	21,145
13		
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41		
42		
43		
44		
45		
46	TOTAL	2,963,630

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			7,263,444		7,263,444
2	Steam Production Plant	108,903,892	3,018,382			111,922,274
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	128,261	973			129,234
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	17,248,213	679			17,248,892
7	Transmission Plant	12,565,952	2,515			12,568,467
8	Distribution Plant	33,896,777	5,974			33,902,751
9	Regional Transmission and Market Operation					
10	General Plant	6,155,170				6,155,170
11	Common Plant-Electric					
12	TOTAL	178,898,265	3,028,523	7,263,444		189,190,232

B. Basis for Amortization Charges

ACCOUNT	RATE	PLANT BALANCE @ 12/31/2011	AMORTIZATION
130200	0 - 5% (1)	55,919	-
130300	20%	18,338,712	3,321,773
130310	10%	40,210,208	3,941,672

			7,263,445 Column (d)
			========

Notes:
(1) Amortization rates vary from 0 - 5%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Intangible Plant						
13	301 Organization	44					
14	302 Frnchses & Consent	56					
15	303 Misc Intngbl Plant	18,339			20.00		
16	303.10 CCS Software	40,210			10.00		
17							
18	Steam Production Plant						
19	310 Land	10,881					
20							
21	311 Strctrs & Imprvmts						
22	5603 Tyrone Unit 3	5,609	100.00	-5.00		100-S1.5	
23	5604 Tyrone Units 1&2	584	100.00	-5.00		100-S1.5	
24	5613 Green Rvr Unit 3	2,821	100.00	-5.00		100-S1.5	
25	5614 Green Rvr Unit 4	5,476	100.00	-5.00		100-S1.5	
26	5615 Green Rvr Unt 1&2	2,561	100.00	-5.00		100-S1.5	
27	5621 Brown Unit 1	4,703	100.00	-5.00	0.60	100-S1.5	19.30
28	5622 Brown Unit 2	2,232	100.00	-5.00	0.08	100-S1.5	19.40
29	5623 Brown Unit 3	21,040	100.00	-5.00	0.54	100-S1.5	19.20
30	5624 Brown 3 FGD	43,917	100.00	-5.00	0.54	100-S1.5	19.20
31	5643 Pineville Unit 3	16	100.00	-5.00		100-S1.5	
32	5650 Ghent Unit 1 FGD	8,484	100.00	-5.00	2.65	100-S1.5	19.30
33	5651 Ghent Unit 1	18,842	100.00	-5.00	0.39	100-S1.5	19.10
34	5652 Ghent Unit 2	16,011	100.00	-5.00	0.50	100-S1.5	19.90
35	5658 Ghent Unit 2 FGD	15,817	100.00	-5.00	2.65	100-S1.5	19.90
36	5653 Ghent Unit 3	42,177	100.00	-5.00	1.19	100-S1.5	28.20
37	5654 Ghent Unit 4	31,022	100.00	-5.00	1.14	100-S1.5	28.30
38	5591 System Laboratory	825	100.00	-5.00	1.54	100-S1.5	28.40
39	0321 Trmble Cty Unit 2	106,291	100.00	-5.00	2.10	100-S1.5	
40	0322 Trmble 2 FGD	5,522	100.00	-5.00	2.10	100-S1.5	
41							
42	312 Boiler Plant Eqpmt						
43	5603 Tyrone Unit 3	13,993	65.00	-20.00	3.99	65-R2	11.10
44	5604 Tyrone Units 1&2	422	65.00	-20.00	0.14	65-R2	
45	5613 Green Rvr Unit 3	12,146	65.00	-20.00	3.08	65-R2	11.10
46	5614 Green Rvr Unit 4	25,166	65.00	-20.00	4.20	65-R2	11.10
47	5615 Green Rvr Unt 1&2	349	65.00	-20.00	2.18	65-R2	11.10
48	5621 Brown Unit 1	45,302	65.00	-20.00	2.98	65-R2	18.20
49	5622 Brown Unit 2	41,957	65.00	-20.00	3.01	65-R2	18.10
50	5623 Brown Unit 3	142,628	65.00	-20.00	2.80	65-R2	18.00

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	5624 Brown 3 FGD	323,725	65.00	-20.00	2.80	65-R2	18.00
13	5643 Pineville Unit 3	237	65.00	-20.00		65-R2	18.40
14	5650 Ghent Unit 1 FGD	144,203	65.00	-20.00	3.87	65-R2	18.20
15	5651 Ghent Unit 1	198,785	65.00	-20.00	3.84	65-R2	18.20
16	5652 Ghent Unit 2	98,447	65.00	-20.00	2.33	65-R2	18.60
17	5658 Ghent Unit 2 FGD	93,279	65.00	-20.00	3.87	65-R2	18.60
18	5653 Ghent Unit 3	254,968	65.00	-20.00	2.63	65-R2	25.60
19	5660 Ghent Unit 3 FGD	127,989	65.00	-20.00	3.87	65-R2	25.60
20	5654 Ghent Unit 4	267,856	65.00	-20.00	2.79	65-R2	25.80
21	5661 Ghent 4 FGD	307,100	65.00	-20.00	3.87	65-R2	25.80
22	5659 Coal Cars		25.00	-20.00	2.41	25-R2	10.80
23	0321 Trmble Cty Unit 2	505,159	65.00	-20.00	4.28	65-R2	
24	0322 Trmble 2 FGD	70,735	65.00	-20.00	4.28	65-R2	
25							
26	314 Turbogenerator Unt						
27	5603 Tyrone Unit 3	4,806	55.00	-15.00	3.44	55-R2.5	11.20
28	5604 Tyrone Units 1&2	68	55.00	-15.00		55-R2.5	
29	5613 Green Rvr Unit 3	4,562	55.00	-15.00	2.90	55-R2.5	11.20
30	5614 Green Rvr Unit 4	10,390	55.00	-15.00	3.79	55-R2.5	11.20
31	5621 Brown Unit 1	7,513	55.00	-15.00	1.12	55-R2.5	16.80
32	5622 Brown Unit 2	12,300	55.00	-15.00	2.91	55-R2.5	17.90
33	5623 Brown Unit 3	29,293	55.00	-15.00	3.17	55-R2.5	18.00
34	5651 Ghent Unit 1	36,687	55.00	-15.00	2.23	55-R2.5	17.40
35	5652 Ghent Unit 2	30,418	55.00	-15.00	2.08	55-R2.5	18.20
36	5653 Ghent Unit 3	42,596	55.00	-15.00	2.03	55-R2.5	23.90
37	5654 Ghent Unit 4	57,037	55.00	-15.00	2.20	55-R2.5	24.60
38	0321 Trmble Cty Unit 2	83,995	55.00	-15.00	2.78	55-R2.5	
39							
40	315 Accessry Elec Eqpm						
41	5603 Tyrone Unit 3	2,082	70.00	-5.00		70-S3	
42	5604 Tyrone Units 1&2	99	70.00	-5.00		70-S3	
43	5613 Green Rvr Unit 3	1,205	70.00	-5.00		70-S3	
44	5614 Green Rvr Unit 4	2,695	70.00	-5.00	1.46	70-S3	11.50
45	5621 Brown Unit 1	3,859	70.00	-5.00	2.10	70-S3	19.50
46	5622 Brown Unit 2	2,166	70.00	-5.00	0.48	70-S3	19.50
47	5623 Brown Unit 3	8,597	70.00	-5.00	0.54	70-S3	19.40
48	5624 Brown 3 FGD	29,504	70.00	-5.00	0.54	70-S3	19.40
49	5650 Ghent Unit 1 FGD	13,293	70.00	-5.00	2.70	70-S3	19.50
50	5651 Ghent Unit 1	8,873	70.00	-5.00	0.55	70-S3	19.50

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	5652 Ghent Unit 2	13,858	70.00	-5.00	0.60	70-S3	19.80
13	5658 Ghent Unit 2 FGD	1,156	70.00	-5.00	2.70	70-S3	19.80
14	5653 Ghent Unit 3	30,932	70.00	-5.00	1.30	70-S3	27.10
15	5660 Ghent Unit 3 FGD	12,042	70.00	-5.00	2.70	70-S3	27.10
16	5654 Ghent Unit 4	24,413	70.00	-5.00	1.22	70-S3	27.80
17	5661 Ghent 4 FGD	3,845	70.00	-5.00	2.70	70-S3	27.80
18	0321 Trmble Cty Unit 2	41,600	70.00	-5.00	2.49	70-S3	
19	0321 Trmble 2 FGD	1,416	70.00	-5.00	2.49	70-S3	
20							
21	316 Misc Plant Equipmt						
22	5603 Tyrone Unit 3	553	70.00		3.12	70-R1.5	11.00
23	5604 Tyrone Units 1&2	50	70.00			70-R1.5	
24	5613 Green Rvr Unit 3	152	70.00		3.97	70-R1.5	11.00
25	5614 Green Rvr Unit 4	2,408	70.00		2.71	70-R1.5	11.10
26	5615 Green Rvr Unt 1&2	85	70.00			70-R1.5	
27	5621 Brown Unit 1	433	70.00		2.26	70-R1.5	17.90
28	5622 Brown Unit 2	107	70.00		0.71	70-R1.5	17.80
29	5623 Brown Unit 3	5,070	70.00		2.33	70-R1.5	17.90
30	5650 Ghent Unit 1 FGD	1,033	70.00		2.87	70-R1.5	18.10
31	5651 Ghent Unit 1	1,748	70.00		1.38	70-R1.5	17.90
32	5652 Ghent Unit 2	1,501	70.00		1.07	70-R1.5	18.60
33	5653 Ghent Unit 3	3,150	70.00		1.40	70-R1.5	25.60
34	5654 Ghent Unit 4	7,455	70.00		2.03	70-R1.5	25.60
35	0321 Trmble Cty Unit 2	3,502	70.00		3.00	70-R1.5	
36	5591 System Labratory	2,763	70.00		2.74	70-R1.5	25.30
37							
38	317 Asset Rtiremt Oblg	56,490					
39							
40	Hydraulic Prodctn Plnt						
41	330.10 Land Rights	879	100.00			100-R4	
42	331 Structrs & Imprvmt	617	90.00	-5.00	1.29	90-S2.5	26.80
43	332 Resrvrs Dams Wtrwy	21,604	100.00		0.72	100-S2.5	27.10
44	333 Wtr Whls Trbns Gen	4,431	80.00	-10.00	0.66	80-R3	23.80
45	334 Wtr Whls Trbns Gen	578	40.00		0.83	40-L2.5	10.70
46	335 Misc Pwr Plnt Eqpm	297	35.00		3.55	35-L1	14.50
47	336 Rds Railrds Bridge	176	55.00			55-R4	
48	337 Asset Retirmt Oblg	58					
49							
50	Other Production Plant						

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Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	340.10 Land Rights	176	30.00		2.97	30-R0.5	16.40
13	340.20 Land	119					
14							
15	341 Strctrs & Imprvmnt						
16	5697 Paddys Run Gen 13	1,910	40.00		3.03	40-R2.5	24.10
17	5635 Brown CT 5	775	40.00		3.04	40-R2.5	24.10
18	5636 Brown CT 6	193	40.00		3.05	40-R2.5	23.70
19	5637 Brown CT 7	545	40.00		2.93	40-R2.5	23.70
20	5638 Brown CT 8	2,013	40.00		2.60	40-R2.5	22.40
21	5639 Brown CT 9	4,641	40.00		2.60	40-R2.5	22.40
22	5640 Brown CT 10	1,866	40.00		2.61	40-R2.5	22.50
23	5641 Brown CT 11	1,895	40.00		2.72	40-R2.5	23.00
24	0470 Trimble Cty CT 5	3,740	40.00		3.14	40-R2.5	24.20
25	0471 Trimble Cty CT 6	3,589	40.00		3.12	40-R2.5	24.20
26	0474 Trimble Cty CT 7	3,559	40.00		3.32	40-R2.5	24.40
27	0475 Trimble Cty CT 8	3,549	40.00		3.32	40-R2.5	24.40
28	0476 Trimble Cty CT 9	3,656	40.00		3.32	40-R2.5	24.40
29	0477 Trimble Cty CT 10	3,653	40.00		3.32	40-R2.5	24.50
30	5696 Haeflg Unts 1,2,3	434	40.00		6.47	40-R2.5	3.50
31							
32	342 Fuel Holders Prdcr						
33	5697 Paddys Run Gen 13	1,995	45.00	-5.00	3.11	45-R2.5	25.20
34	5635 Brown CT 5	796	45.00	-5.00	3.11	45-R2.5	25.20
35	5636 Brown CT 6	406	45.00	-5.00	2.92	45-R2.5	24.90
36	5637 Brown CT 7	406	45.00	-5.00	2.92	45-R2.5	24.90
37	5638 Brown CT 8	252	45.00	-5.00	2.63	45-R2.5	24.00
38	5639 Brown CT 9	2,019	45.00	-5.00	2.65	45-R2.5	24.10
39	5640 Brown CT 10	264	45.00	-5.00	2.63	45-R2.5	24.00
40	5641 Brown CT 11	285	45.00	-5.00	2.74	45-R2.5	24.40
41	5645 Brown CT 9 Gas PL	8,106	45.00	-5.00	2.57	45-R2.5	23.80
42	0470 Trimble Cty CT 5	240	45.00	-5.00	3.21	45-R2.5	25.30
43	0471 Trimble Cty CT 6	239	45.00	-5.00	3.21	45-R2.5	25.30
44	0473 Trmbl Cty CT PipL	4,850	45.00	-5.00	3.23	45-R2.5	25.30
45	0474 Trimble Cty CT 7	578	45.00	-5.00	3.42	45-R2.5	25.30
46	0475 Trimble Cty CT 8	576	45.00	-5.00	3.42	45-R2.5	25.40
47	0476 Trimble Cty CT 9	594	45.00	-5.00	3.42	45-R2.5	25.30
48	0477 Trimble Cty CT 10	623	45.00	-5.00	3.42	45-R2.5	25.30
49	5696 Haeflg Unts 1,2,3	519	45.00	-5.00		45-R2.5	
50							

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	343 Prime Movers						
13	5697 Paddys Run Gen 13	17,803	35.00	-5.00	3.62	35-R1	19.20
14	5635 Brown CT 5	14,667	35.00	-5.00	3.65	35-R1	18.90
15	5636 Brown CT 6	34,600	35.00	-5.00	3.55	35-R1	18.60
16	5637 Brown CT 7	31,658	35.00	-5.00	3.58	35-R1	18.60
17	5638 Brown CT 8	26,711	35.00	-5.00	3.30	35-R1	18.50
18	5639 Brown CT 9	23,335	35.00	-5.00	3.23	35-R1	18.60
19	5640 Brown CT 10	20,075	35.00	-5.00	3.26	35-R1	18.60
20	5641 Brown CT 11	34,795	35.00	-5.00	3.41	35-R1	19.20
21	0470 Trimble Cty CT 5	31,138	35.00	-5.00	3.72	35-R1	19.10
22	0471 Trimble Cty CT 6	32,030	35.00	-5.00	3.72	35-R1	19.10
23	0474 Trimble Cty CT 7	23,223	35.00	-5.00	3.91	35-R1	18.40
24	0475 Trimble Cty CT 8	23,035	35.00	-5.00	3.91	35-R1	18.40
25	0476 Trimble Cty CT 9	22,902	35.00	-5.00	3.91	35-R1	18.40
26	0477 Trimble Cty CT 10	22,851	35.00	-5.00	3.91	35-R1	18.40
27							
28	344 Generators						
29	5697 Paddys Run Gen 13	5,186	55.00	-5.00	2.94	55-S3	29.00
30	5635 Brown CT 5	2,858	55.00	-5.00	2.94	55-S3	29.00
31	5636 Brown CT 6	3,713	55.00	-5.00	2.76	55-S3	28.70
32	5637 Brown CT 7	3,723	55.00	-5.00	2.76	55-S3	28.70
33	5638 Brown CT 8	4,954	55.00	-5.00	2.46	55-S3	28.00
34	5639 Brown CT 9	5,452	55.00	-5.00	2.31	55-S3	27.80
35	5640 Brown CT 10	4,944	55.00	-5.00	2.46	55-S3	28.00
36	5641 Brown CT 11	5,187	55.00	-5.00	2.53	55-S3	28.30
37	0470 Trimble Cty CT 5	3,763	55.00	-5.00	3.04	55-S3	29.10
38	0471 Trimble Cty CT 6	3,758	55.00	-5.00	3.04	55-S3	29.10
39	0474 Trimble Cty CT 7	2,950	55.00	-5.00	3.26	55-S3	29.20
40	0475 Trimble Cty CT 8	2,938	55.00	-5.00	3.26	55-S3	29.20
41	0476 Trimble Cty CT 9	2,958	55.00	-5.00	3.26	55-S3	29.20
42	0477 Trimble Cty CT 10	2,954	55.00	-5.00	3.26	55-S3	29.20
43	5696 Haeflg Unts 1,2,3	4,023	55.00	-5.00		55-S3	
44							
45	345 Assesry Elec Eqpmt						
46	5697 Paddys Run Gen 13	2,456	45.00		2.88	45-R3	26.40
47	5635 Brown CT 5	2,277	45.00		2.89	45-R3	26.40
48	5636 Brown CT 6	1,975	45.00		2.71	45-R3	25.90
49	5637 Brown CT 7	1,936	45.00		2.71	45-R3	25.90
50	5638 Brown CT 8	2,721	45.00		2.41	45-R3	24.80

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Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	5639 Brown CT 9	4,206	45.00		2.32	45-R3	24.80
13	5640 Brown CT 10	2,744	45.00		2.44	45-R3	25.00
14	5641 Brown CT 11	1,863	45.00		2.48	45-R3	25.10
15	0470 Trimble Cty CT 5	1,694	45.00		2.98	45-R3	26.60
16	0471 Trimble Cty CT 6	4,325	45.00		2.98	45-R3	26.60
17	0474 Trimble Cty CT 7	3,148	45.00		3.19	45-R3	26.90
18	0475 Trimble Cty CT 8	3,139	45.00		3.19	45-R3	26.90
19	0476 Trimble Cty CT 9	3,234	45.00		3.19	45-R3	26.90
20	0477 Trimble Cty CT 10	7,197	45.00		3.19	45-R3	26.90
21	5696 Haeflg Unts 1,2,3	1,452	45.00			45-R3	
22							
23	346 Misc Plant Equipmt						
24	5697 Paddys Run Gen 13	1,090	35.00		3.20	35-R2	21.40
25	5635 Brown CT 5	2,139	35.00		3.20	35-R2	21.40
26	5636 Brown CT 6	54	35.00		3.33	35-R2	21.30
27	5637 Brown CT 7	36	35.00		3.23	35-R2	21.30
28	5638 Brown CT 8	286	35.00		2.77	35-R2	19.60
29	5639 Brown CT 9	760	35.00		2.77	35-R2	19.60
30	5640 Brown CT 10	274	35.00		2.85	35-R2	19.90
31	5641 Brown CT 11	591	35.00		3.22	35-R2	21.10
32	0470 Trimble Cty CT 5	28	35.00		3.73	35-R2	20.30
33	0474 Trimble Cty CT 7	9	35.00		3.50	35-R2	21.70
34	0475 Trimble Cty CT 8	9	35.00		3.50	35-R2	21.70
35	0476 Trimble Cty CT 9	9	35.00		3.50	35-R2	21.60
36	0477 Trimble Cty CT 10	42	35.00		3.49	35-R2	21.70
37	5696 Haeflg Unts 1,2,3	36	35.00			35-R2	
38							
39	347 Asset Rtirmt Oblg	18					
40							
41	Transmission Plant						
42	350.1 Land Rights	23,414	60.00		0.98	60-R3	31.70
43	350.2 Land	2,199					
44	352.1 Strct Impr Non S	17,020	65.00	-25.00	1.54	65-S2.5	40.20
45	352.2 Strct Impr Sys C	1,220	60.00	-25.00	1.43	60-R3	34.00
46	353.1 Station Equipmnt	191,754	60.00	-20.00	1.98	60-R2	34.80
47	353.2 Sys Cntrl Mcrwv	14,668	30.00	-20.00	0.46	30-R2.5	20.50
48	354 Towers & Fixtures	95,353	70.00	-25.00	1.21	70-R4	43.80
49	355 Poles & Fixtures	148,659	50.00	-60.00	2.28	50-R2	30.70
50	356 Ovrhd Cndctr Dvcs	160,447	60.00	-50.00	1.79	60-R3	35.50

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Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	357 Undrgrnd Conduit	449	40.00		2.60	40-L2.5	21.90
13	358 Undrgrnd Cndctrs D	1,162	35.00		1.26	35-R3	19.40
14	359 Transmission AROs	540					
15							
16	Distribution Plant						
17	360.1 Land Rights	2,039	65.00		0.65	65-R4	45.10
18	360.2 Land	3,272					
19	361 Strctrs & Imprvmnt	7,658	60.00	-10.00	1.65	60-R2.5	38.10
20	362 Station Equipment	141,201	52.00	-15.00	2.28	52-R2	29.90
21	364 Poles Twrs Fixture	287,792	48.00	-45.00	2.30	48-S0	27.40
22	365 Ovrhd Cndctrs Dvc	276,286	48.00	-75.00	2.70	48-R2	27.60
23	366 Undrgrnd Conduit	1,862	55.00		1.93	55-S4	28.80
24	367 Undrgrnd Cndctrs D	140,620	44.00	-5.00	2.09	44-S0.5	27.50
25	368 Line Transformers	286,070	40.00	-20.00	3.10	40-R2	21.90
26	369 Services	89,050	43.00	-30.00	1.99	43-R1.5	25.80
27	370 Meters	70,049	40.00		1.76	40-R1.5	20.90
28	371 Instltns Cust Prms	18,253	20.00	-10.00	2.38	20-R0.5	10.90
29	373 St Lghtng Sgnl Sys	81,535	33.00	-5.00	2.29	33-R1	19.10
30	374 Asset Rtrmnt Cost	787					
31							
32	General Plant						
33	389.2 Land	2,568					
34	390.1 Strctrs Imprvmnt	47,011	60.00	-5.00	1.66	60-S0	33.90
35	390.2 Imprvmt Lesd Prp	532	30.00	-5.00	1.56	30-R1	17.20
36	391.1 Ofc Furnitur Eqp	7,514	20.00		4.19	20-SQ	13.60
37	391.2 Non PC Cmptr Eqp	17,256	5.00		10.14	5-SQ	3.30
38	391.3 Cash Processing		10.00		23.26	10-SQ	1.50
39	391.31 Prsnl Comptr Eq	6,398	4.00		15.47	4-SQ	2.80
40	392 Transportation Eqp	15,967	5.00		20.00	5-SQ	
41	393 Stores Equipment	552	25.00		5.25	25-SQ	11.60
42	394 Tool Shop Garage E	7,649	25.00		4.75	25-SQ	14.70
43	395 Laboratory Equipmt		15.00		27.42	15-SQ	1.80
44	396 Pwr Operated Eqp	1,174	17.00		6.37	17-R5	9.60
45	397 Communication Eqpm	30,873	15.00		7.13	15-SQ	10.90
46	398 Misc Equipment		10.00		20.54	10-SQ	1.80
47							
48							
49							
50							

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission				
2	Annual Charge	452,450		452,450	
3	2008 Rate Case		12,877	12,877	
4					
5	Tennessee Regulatory Authority				
6	2008 Rate Filing		-25	-25	
7					
8	State Corporation Commission of Virginia				
9	2008 Rate Case				
10	2010 Rate Case		268,903	268,903	
11					
12	2008 Rate Case (Mar-09 to Feb-12)		460,559	460,559	537,318
13	2009 Rate Case (Aug-10 to Jul-13)		671,523	671,523	1,734,767
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	452,450	1,413,837	1,866,287	2,272,085

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Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	452,449					2
Electric	928	12,877					3
							4
							5
Electric	928	-25					6
							7
							8
							9
Electric	928	268,903					10
							11
Electric	928	460,559			460,559	76,760	12
Electric	928	671,522		928	671,522	1,063,244	13
							14
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		1,866,285			1,132,081	1,140,004	46

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Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2011/Q4

FOOTNOTE DATA

Schedule Page: 350 Line No.: 6 Column: c

Negative amount represents a correction from the prior year.

Schedule Page: 350 Line No.: 6 Column: h

Negative amount represents a correction from the prior year.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
 (1) Generation
  a. hydroelectric
   i. Recreation fish and wildlife
   ii Other hydroelectric
  b. Fossil-fuel steam
  c. Internal combustion or gas turbine
  d. Nuclear
  e. Unconventional generation
  f. Siting and heat rejection
 (2) Transmission
  a. Overhead
  b. Underground
 (3) Distribution
 (4) Regional Transmission and Market Operation
 (5) Environment (other than equipment)
 (6) Other (Classify and include items in excess of $50,000.)
 (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
 (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	EPRI (1)	Tailored Collaboration
2	EPRI (1)	BSA Power Plant Parameter Derivation Software User's Group
3	EPRI (1)	Green Substations Interest Groups
4	EPRI (1)	Annual Membership and Annual Research Portfolio
5	EPRI (1)	CO2 Carbon Capture Technology Assessment
6	EPRI (1)	Tailored Collaboration
7	EPRI (1)	Annual Membership and Annual Research Portfolio
8	Kentucky Consortium for Carbon Storage (4)	Amortization of Carbon Storage Project Regulatory Asset
9	University of Kentucky Research Foundation (4)	Power Flow and Stability Analysis
10	University of Kentucky Research Foundation (4)	Evaluation of Geologic Carbon Storage
11	University of Kentucky Research Foundation (4)	Amortization of Carbon Capturing Research Regulatory Asset
12	Moore Ventures LLC (4)	Biomass Feasibility Study
13	Seismic Specialists Inc. (4)	Geological Survey
14	University of Texas at Austin, The (4)	Annual Subscription to the Luminant Carbon Management Program
15	Gottuso, Leeann (4)	Engineering Studies
16	Meiners Electric (4)	EPRI Project
17	Kellogg Brown and Root, LLC (4)	Carbon Capture Project
18	Youngblood Construction (4)	Engineering Studies
19	PIC Group, Inc. (4)	Engineering Studies
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
	10,903	500	10,903		1
	3,600	510	3,600		2
	6,222	566	6,222		3
	56,530	908	56,530		4
	11,888	923	11,888		5
	346,124	930	346,124		6
	1,537,026	930	1,537,026		7
	230,490	930	230,490		8
	31,039	561	31,039		9
	10,673	923	10,673		10
	102,440	930	102,440		11
	14,616	923	14,616		12
	7,400	923	7,400		13
	10,750	930	10,750		14
	64	930	64		15
	6,011	930	6,011		16
	128,491	923	128,491		17
	139	930	139		18
	7,509	930	7,509		19
					20
	2,521,915		2,521,915		21
					22
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	21,944,650		
4	Transmission	3,552,759		
5	Regional Market			
6	Distribution	9,433,162		
7	Customer Accounts	9,052,948		
8	Customer Service and Informational	823,575		
9	Sales			
10	Administrative and General	16,616,054		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	61,423,148		
12	Maintenance			
13	Production	14,605,723		
14	Transmission	786,482		
15	Regional Market			
16	Distribution	5,844,256		
17	Administrative and General	4,504,662		
18	TOTAL Maintenance (Total of lines 13 thru 17)	25,741,123		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	36,550,373		
21	Transmission (Enter Total of lines 4 and 14)	4,339,241		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	15,277,418		
24	Customer Accounts (Transcribe from line 7)	9,052,948		
25	Customer Service and Informational (Transcribe from line 8)	823,575		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	21,120,716		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	87,164,271	21,789,282	108,953,553
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	87,164,271	21,789,282	108,953,553
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	19,606,995	14,409,438	34,016,433
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	19,606,995	14,409,438	34,016,433
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,172,124	945,952	2,118,076
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,172,124	945,952	2,118,076
77	Other Accounts (Specify, provide details in footnote):			
78	Accounts Receivable	3,523,957	493,396	4,017,353
79	Miscellaneous Deferred Debits & Preliminary Survey	5,838	656,619	662,457
80	Certain Civic, Political and Related Activities and Other	438,407	136,878	575,285
81	Nonjurisdictional	11,900	3,470	15,370
82				
83				
84				
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86				
87				
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89				
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91				
92				
93				
94				
95	TOTAL Other Accounts	3,980,102	1,290,363	5,270,465
96	TOTAL SALARIES AND WAGES	111,923,492	38,435,035	150,358,527

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2011/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	259,073	2,183,734	3,612,764	3,625,547
3	Net Sales (Account 447)	388,498	1,552,431	2,111,914	3,183,200
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
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46	TOTAL	647,571	3,736,165	5,724,678	6,808,747

Schedule Page: 397 Line No.: 2 Column: b

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the purchase amount recorded in accordance with FERC Order No. 668-A would have been $257,345.

Schedule Page: 397 Line No.: 2 Column: c

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the purchase amount recorded in accordance with FERC Order No. 668-A would have been $2,182,006.

Schedule Page: 397 Line No.: 2 Column: d

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the purchase amount recorded in accordance with FERC Order No. 668-A would have been $3,609,962.

Schedule Page: 397 Line No.: 2 Column: e

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the purchase amount recorded in accordance with FERC Order No. 668-A would have been $3,622,746.

Schedule Page: 397 Line No.: 3 Column: b

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the sale amount recorded in accordance with FERC Order No. 668-A would have been $388,383. These amounts do not include $184 in sales sourced by test energy from the commissioning of a new power plant that were assigned to Account 107 rather than to Account 447 during the first quarter. There is no difference in the Day Ahead and Real Time markets for the sales which were assigned to Account 107.

Schedule Page: 397 Line No.: 3 Column: c

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the sale amount recorded in accordance with FERC Order No. 668-A would have been $1,552,317. These amounts do not include $184 in sales sourced by test energy from the commissioning of a new power plant that were assigned to Account 107 rather than to Account 447 during the first quarter. There is no difference in the Day Ahead and Real Time markets for the sales which were assigned to Account 107.

Schedule Page: 397 Line No.: 3 Column: d

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's

Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the sale amount recorded in accordance with FERC Order No. 668-A would have been $2,111,592. These amounts do not include $184 in sales sourced by test energy from the commissioning of a new power plant that were assigned to Account 107 rather than to Account 447 during the first quarter. There is no difference in the Day Ahead and Real Time markets for the sales which were assigned to Account 107.

Schedule Page: 397 Line No.: 3 Column: e

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the sale amount recorded in accordance with FERC Order No. 668-A would have been $3,182,878. These amounts do not include $184 in sales sourced by test energy from the commissioning of a new power plant that were assigned to Account 107 rather than to Account 447 during the first quarter. There is no difference in the Day Ahead and Real Time markets for the sales which were assigned to Account 107.

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	647,192	MWH	168,073	4,499,406	MWH	381,921
2	Reactive Supply and Voltage	647,192	MWH	106,516	4,499,406	MWH	255,536
3	Regulation and Frequency Response				4,499,406	MWH	95,047
4	Energy Imbalance						
5	Operating Reserve - Spinning				4,499,406	MWH	147,323
6	Operating Reserve - Supplement				4,499,406	MWH	147,323
7	Other			24,285			
8	Total (Lines 1 thru 7)	1,294,384		298,874	22,497,030		1,027,150

Schedule Page: 398 Line No.: 7 Column: b

The Other charges are not associated with a number of units or a unit of measure.

Schedule Page: 398 Line No.: 7 Column: d

This amount consists of PJM non-energy related charges related to non-firm point-to-point transmission services and Black Start Charges. This amount also includes the Midwest ISO’s Schedule 26 Charges (Network Upgrade Charge from Transmission Expansion Plan.)

PJM Other Charges:	$ 23,610
MISO Schedule 26:	675
	$ 24,285

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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2011/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,931	12	19	4,066	493	314	58		
2	February	5,175	11	8	4,292	510	314	59		
3	March	4,120	10	20	3,231	414	314	53	107	
4	Total for Quarter 1	14,226			11,589	1,417	942	170	107	
5	April	4,027	1	7	3,125	402	314	43	143	
6	May	5,262	31	16	3,846	674	314	55	373	
7	June	4,883	8	16	3,920	593	314	56		
8	Total for Quarter 2	14,172			10,891	1,669	942	154	516	
9	July	5,207	11	16	4,102	733	314	58		
10	August	5,098	2	16	4,061	630	314	57	36	
11	September	5,266	1	16	3,969	710	314	58	215	
12	Total for Quarter 3	15,571			12,132	2,073	942	173	251	
13	October	3,832	7	17	2,784	479	314	31	224	
14	November	4,430	18	8	3,374	545	314	54	143	
15	December	4,467	12	8	3,537	561	314	55		
16	Total for Quarter 4	12,729			9,695	1,585	942	140	367	
17	Total Year to Date/Year	56,698			44,307	6,744	3,768	637	1,241	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	19,256,438
3	Steam	18,606,037			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	1,905,867
5	Hydro-Conventional	81,629			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,219,346
7	Other	322,262			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	54
9	Net Generation (Enter Total of lines 3 through 8)	19,009,928	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	22,015
10	Purchases	4,188,345	27	Total Energy Losses	1,132,091
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	23,535,811
12	Received	199,226			
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)	199,226			
15	Transmission For Other (Wheeling)				
16	Received	4,499,406			
17	Delivered	4,361,094			
18	Net Transmission for Other (Line 16 minus line 17)	138,312			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	23,535,811			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: KU

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	2,398,012	103,401	4,092	12	1100
30	February	1,971,120	127,582	4,292	11	800
31	March	1,909,483	102,928	3,251	10	2100
32	April	1,606,384	32,751	3,125	1	700
33	May	1,769,658	107,631	3,855	31	1500
34	June	2,001,987	120,379	3,935	8	1500
35	July	2,237,821	97,203	4,147	20	1600
36	August	2,127,211	51,601	4,061	2	1600
37	September	1,729,137	90,422	4,024	2	1600
38	October	1,840,767	189,730	2,823	20	1000
39	November	1,763,372	74,196	3,374	18	800
40	December	2,180,859	121,522	3,546	8	800
41	TOTAL	23,535,811	1,219,346			

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Schedule Page: 401 Line No.: 29 Column: b

The value reported in the first quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 2,490,859 MWH.

Schedule Page: 401 Line No.: 30 Column: b

The value reported in the first quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 2,059,129 MWH.

Schedule Page: 401 Line No.: 31 Column: b

The value reported in the first quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 1,965,777 MWH.

Schedule Page: 401 Line No.: 32 Column: b

The value reported in the second quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 1,610,181 MWH.

Schedule Page: 401 Line No.: 33 Column: b

The value reported in the second quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 1,857,509 MWH.

Schedule Page: 401 Line No.: 34 Column: b

The value reported in the second quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 2,103,770 MWH.

Schedule Page: 401 Line No.: 35 Column: b

The value reported in the third quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 2,339,376MWH.

Schedule Page: 401 Line No.: 36 Column: b

The value reported in the third quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 2,205,654 MWH.

Schedule Page: 401 Line No.: 37 Column: b

The value reported in the third quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 1,779,454 MWH.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Tyrone* (b)			Plant Name: *Green River* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Conventional			Conventional
3	Year Originally Constructed			1947			1950
4	Year Last Unit was Installed			1971			1959
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			75.00			189.00
6	Net Peak Demand on Plant - MW (60 minutes)			72			177
7	Plant Hours Connected to Load			616			6695
8	Net Continuous Plant Capability (Megawatts)			73			171
9	When Not Limited by Condenser Water			73			171
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			11			54
12	Net Generation, Exclusive of Plant Use - KWh			22022000			788480000
13	Cost of Plant: Land and Land Rights			53143			30764
14	Structures and Improvements			6192207			10858255
15	Equipment Costs			22073290			59159392
16	Asset Retirement Costs			2623932			8444632
17	Total Cost			30942572			78493043
18	Cost per KW of Installed Capacity (line 17/5) Including			412.5676			415.3071
19	Production Expenses: Oper, Supv, & Engr			273426			386898
20	Fuel			1395693			25486084
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			100138			1485509
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			22299			1228971
26	Misc Steam (or Nuclear) Power Expenses			492300			902462
27	Rents			0			0
28	Allowances			706			65969
29	Maintenance Supervision and Engineering			59446			1145432
30	Maintenance of Structures			58748			623309
31	Maintenance of Boiler (or reactor) Plant			169997			3252032
32	Maintenance of Electric Plant			8290			560695
33	Maintenance of Misc Steam (or Nuclear) Plant			3442			726349
34	Total Production Expenses			2584485			35863710
35	Expenses per Net KWh			0.1174			0.0455
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Coal	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	tons	barrels		tons	barrels	
38	Quantity (Units) of Fuel Burned	12671	882	0	383785	4593	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12775	3333	0	12075	3333	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	99.970	110.461	0.000	61.570	127.426	0.000
41	Average Cost of Fuel per Unit Burned	102.456	110.461	0.000	64.882	127.426	0.000
42	Average Cost of Fuel Burned per Million BTU	4.010	18.783	0.000	2.687	21.671	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.059	0.000	0.000	0.032	0.000	0.000
44	Average BTU per KWh Net Generation	14701.000	0.000	0.000	11755.000	0.000	0.000

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Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *EW Brown* (d)			Plant Name: *Ghent* (e)			Plant Name: *Trimble County* (f)			Line No.
		Steam			Steam			Steam	1
		Conventional			Conventional			Conventional	2
		1957			1973			2011	3
		1971			1984			2011	4
		757.00			2226.00			679.00	5
		691			1983			629	6
		6381			7874			6610	7
		691			1931			616	8
		691			1931			616	9
		0			0			0	10
		152			223			150	11
		2497925000			12505739000			3739167000	12
		899869			9842884			6841	13
		71892185			133178476			111812888	14
		652454449			1785424966			706407294	15
		16248543			24361749			3710825	16
		741495046			1952808075			821937848	17
		979.5179			877.2723			1210.5123	18
		1641951			2800352			764086	19
		95639381			305446414			83209442	20
		0			0			0	21
		3835339			10958750			2322167	22
		0			0			0	23
		0			0			0	24
		2054143			3207263			687254	25
		1782958			18291193			4029518	26
		14923			0			0	27
		6183			42716			15	28
		1826536			4214753			362954	29
		1467413			3560027			674959	30
		7892894			23532885			4322061	31
		1878784			9260621			585882	32
		593895			781034			362968	33
		118634400			382096008			97321306	34
		0.0475			0.0306			0.0260	35
Coal	Oil		Coal	Oil		Coal	Oil		36
tons	barrels		tons	barrels		tons	barrels		37
1194587	13245	0	5904939	22918	0	1637009	35062	0	38
11885	3333	0	11521	3333	0	10703	3333	0	39
77.880	119.625	0.000	52.040	114.641	0.000	45.550	129.030	0.000	40
78.734	119.625	0.000	51.282	114.641	0.000	48.067	129.030	0.000	41
3.312	20.345	0.000	2.226	19.497	0.000	2.246	21.944	0.000	42
0.038	0.000	0.000	0.024	0.000	0.000	0.021	0.000	0.000	43
11367.000	0.000	0.000	10880.000	0.000	0.000	9371.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Haefling* (b)			Plant Name: *Brown CT* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combustion Turbine			Combustion Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Conventional		
3	Year Originally Constructed	1970			1994		
4	Year Last Unit was Installed	1970			2001		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	62.00			781.00		
6	Net Peak Demand on Plant - MW (60 minutes)	34			526		
7	Plant Hours Connected to Load	24			165		
8	Net Continuous Plant Capability (Megawatts)	42			805		
9	When Not Limited by Condenser Water	42			805		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	328000			55438000		
13	Cost of Plant: Land and Land Rights	0			275012		
14	Structures and Improvements	434853			11927303		
15	Equipment Costs	6029470			251067909		
16	Asset Retirement Costs	0			17791		
17	Total Cost	6464323			263288015		
18	Cost per KW of Installed Capacity (line 17/5) Including	104.2633			337.1165		
19	Production Expenses: Oper, Supv, & Engr	0			193379		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			19426		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	231237			5267168		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			18460		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1800			55459		
30	Maintenance of Structures	61410			229115		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	101537			1169999		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	395984			6953006		
35	Expenses per Net KWh	1.2073			0.1254		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil		Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	mcf	barrels		mcf	barrels	
38	Quantity (Units) of Fuel Burned	44431	59	0	786902	11773	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	464	3330	0	1025	3333	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.713	57.994	0.000	5.142	98.374	0.000
41	Average Cost of Fuel per Unit Burned	3.713	57.994	0.000	5.142	98.374	0.000
42	Average Cost of Fuel Burned per Million BTU	8.009	9.832	0.000	5.016	16.730	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.503	0.000	0.000	0.080	0.231	0.000
44	Average BTU per KWh Net Generation	62796.000	0.000	0.000	15995.000	13812.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Paddy's Run 13 CT* (d)	Plant Name: *Trimble County CT* (e)	Plant Name: (f)	Line No.
Combustion Turbine	Combustion Turbine		1
Conventional	Conventional		2
2001	2002		3
2001	2004		4
84.00	784.00	0.00	5
59	611	0	6
95	616	0	7
82	693	0	8
82	693	0	9
0	0	0	10
0	0	0	11
14777000	251719000	0	12
0	19912	0	13
1910329	21745929	0	14
28529970	205034607	0	15
0	0	0	16
30440299	226800448	0	17
362.3845	289.2863	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	304045	0	22
0	0	0	23
0	0	0	24
1249181	26024705	0	25
0	0	0	26
6179	7422	0	27
0	0	0	28
0	0	0	29
14172	0	0	30
0	0	0	31
648086	506783	0	32
0	0	0	33
1917618	26842955	0	34
0.1298	0.1066	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Gas			Gas						36
mcf			mcf						37
159879	0	0	2983325	0	0	0	0	0	38
1025	0	0	1025	0	0	0	0	0	39
7.777	0.000	0.000	8.723	0.000	0.000	0.000	0.000	0.000	40
7.777	0.000	0.000	8.723	0.000	0.000	0.000	0.000	0.000	41
7.587	0.000	0.000	8.511	0.000	0.000	0.000	0.000	0.000	42
0.084	0.000	0.000	0.103	0.000	0.000	0.000	0.000	0.000	43
11090.000	0.000	0.000	12148.000	0.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

									Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

BLANK

Schedule Page: 402 Line No.: -1 Column: f

Partnership Expenses included in column f:

Line 19	Production Expenses: Oper, Supv, & Engr	$ (191,022)
Line 20	Fuel	(21,168,861)
Line 22	Steam Expenses	(584,234)
Line 25	Electric Expenses	(171,814)
Line 26	Misc Steam Power Expenses	(1,007,380)
Line 28	Allowances	(4)
Line 29	Maintenance Supervision and Engineering	(90,739)
Line 30	Maintenance of Structures	(168,740)
Line 31	Maintenance of Boiler Plant	(1,080,516)
Line 32	Maintenance of Electric Plant	(146,471)
Line 33	Maintenance of Misc Steam Plant	(90,742)
Line 34	Total Production Expenses	$ (24,700,523)

Schedule Page: 402.1 Line No.: -1 Column: f

Pineville Generating Station is fully retired. However, land and ashpond assets amounting to $1,400,367 remain on the books.

Schedule Page: 402.1 Line No.: 5 Column: c

The Nameplate Rating for Brown CT represents a 47% ownership of unit 5, a 123 MW unit, and 62% ownership of units 6 and 7, which are 177 MW each, for KU. The remaining percentages of units 5, 6 and 7 are owned by LG&E.

Schedule Page: 402.1 Line No.: 5 Column: d

The Nameplate Rating for Paddy's Run 13 CT represents a 47% ownership for KU. Total Nameplate Rating for the unit is 178 MW. The remaining percentage is owned by LG&E.

Schedule Page: 402.1 Line No.: 5 Column: e

The Nameplate Rating for Trimble County CT represents 71% ownership of units 5 and 6 and 63% of units 7, 8, 9 and 10 for KU. The remaining percentages for units 5, 6, 7, 8, 9 and 10 are owned by LG&E. Total Nameplate Ratings for these units are 199 MW per unit.

Schedule Page: 402.1 Line No.: 11 Column: b

No production/operation employees are directly assigned to Haefling turbines. Employees from the Brown Plant operate and maintain the Haefling turbines.

Schedule Page: 402.1 Line No.: 11 Column: c

Employees at the Brown Plant include those assigned to the steam plant and the Brown CT site and are reflected in the Brown Steam Plant statistics.

Schedule Page: 402.1 Line No.: 11 Column: d

No production/operation employees are directly assigned to Paddy's Run turbines. Employees from the LG&E Cane Run Plant operate and maintain the Paddy's Run turbines.

Schedule Page: 402.1 Line No.: 11 Column: e

Employees at the Trimble County Plant include those assigned to the steam plant and the Trimble County CT site and are reflected in the Trimble County steam plant statistics.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Dix Dam (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1923	
4	Year Last Unit was Installed	1924	
5	Total installed cap (Gen name plate Rating in MW)	28.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	29	0
7	Plant Hours Connect to Load	4,338	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	24	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	3	0
12	Net Generation, Exclusive of Plant Use - Kwh	81,629,000	0
13	Cost of Plant		
14	Land and Land Rights	879,312	0
15	Structures and Improvements	616,527	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	27,086,309	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	57,609	0
20	TOTAL cost (Total of 14 thru 19)	28,639,757	0
21	Cost per KW of Installed Capacity (line 20 / 5)	1,022.8485	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	7,598	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	57,700	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	113,239	0
30	Maintenance of Structures	163,161	0
31	Maintenance of Reservoirs, Dams, and Waterways	42,400	0
32	Maintenance of Electric Plant	97,829	0
33	Maintenance of Misc Hydraulic Plant	10,289	0
34	Total Production Expenses (total 23 thru 33)	492,216	0
35	Expenses per net KWh	0.0060	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Pocket	Pineville	500.00	500.00	ST	35.48		
2	Pocket	Phipps Bend	500.00	500.00	ST	21.39		
3								
4	Ghent Plant	Brown North	345.00	345.00	ST	113.87		
5	Ghent Plant	Batesville	345.00	345.00	ST	7.80		
6	Brown Plant	Elmer Smith	345.00	345.00	HF &ST	171.06		
7	Brown North	K.U. Park	345.00	345.00	ST	102.47		2
8	Grahamville	DOE	161.00	161.00	SP	1.69		
9	Green River	AEC Buss	161.00	161.00	HF,ST & WP	181.40		
10	Green River	Morganfield	161.00	161.00	HF & WP	55.38		
11	Elihu	Dorchester	161.00	161.00	HF & ST	86.06		
12	Lake Reba	Dorchester	161.00	161.00	HF & ST	99.15		1
13	Pineville	Harlan	161.00	161.00	HF & WP	48.34		
14	Pineville 149	Pineville 192	161.00	161.00	HF	0.12		1
15	East Ky. Power	Taylor County	161.00	161.00	SP	3.97		1
16	Imboden	Harlan	161.00	161.00	HF,SP,WP,ST	43.82		
17								
18	Ghent Plant	Brown Plant	138.00	138.00	ST	90.47		
19	Brown Plant	Green River	138.00	138.00	HF,SP & ST	169.18		
20	Kenton	Rodburn	138.00	138.00	HF	45.74		1
21	Green River	Brown North	138.00	138.00	HF & ST	166.58		
22	Fawkes	Rodburn	138.00	138.00	HF,ST & WP	64.52		1
23	Clifty Creek	Carrollton	138.00	138.00	HF,SP,ST,WP	144.71		
24	Brown Plant	Lake Reba	138.00	138.00	HF	29.44		1
25	Brown Plant	Haefling	138.00	138.00	HF,SP,ST,WP	29.32		
26	Ghent Plant	Kenton Station	138.00	138.00	HF & WF	72.78		1
27	Ghent Plant	Adams	138.00	138.00	HF,SP & ST	56.77		
28	Hardin County	Rogersville	138.00	138.00	HF	10.24		1
29	Virginia City	Clinch River (AEP Int. Pt)	138.00	138.00	HF	7.89		1
30	69KV Lines		69.00	69.00	Various	2,218.75		
31								
32								
33								
34	Exp Applicable to All Lines							
35								
36					TOTAL	4,078.39		11

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954mcm	1,385,561	15,459,178	16,844,739					1
954mcm	280,371	7,950,059	8,230,430					2
								3
795mcm	2,495,681	16,990,017	19,485,698					4
954mcm	437,159	6,003,194	6,440,353					5
954mcm	1,615,764	17,774,802	19,390,566					6
954mcm	1,111,580	21,484,538	22,596,118					7
1272mcm		2,444,040	2,444,040					8
556mcm	1,284,447	14,075,955	15,360,402					9
556mcm	268,660	2,065,603	2,334,263					10
556mcm	270,147	4,140,756	4,410,903					11
556mcm	559,988	4,757,149	5,317,137					12
795mcm	300,849	6,242,117	6,542,966					13
954mcm		14,306	14,306					14
556mcm	261,988	307,188	569,176					15
795mcm	84,143	4,697,455	4,781,598					16
								17
954mcm	419,701	5,837,035	6,256,736					18
556mcm	381,153	12,811,298	13,192,451					19
397mcm	98,119	1,298,430	1,396,549					20
795mcm	732,413	66,178,781	66,911,194					21
556mcm	579,168	2,233,650	2,812,818					22
795mcm	891,092	15,217,694	16,108,786					23
556mcm	80,240	1,215,179	1,295,419					24
795mcm	191,989	4,967,477	5,159,466					25
795mcm	446,861	5,438,171	5,885,032					26
795mcm	245,501	5,190,941	5,436,442					27
795mcm	245,093	953,484	1,198,577					28
795mcm	344,137	4,788,455	5,132,592					29
Various	8,294,395	156,619,227	164,913,622					30
								31
								32
								33
				466,728	4,736,339	97,338	5,300,405	34
								35
	23,306,200	407,156,179	430,462,379	466,728	4,736,339	97,338	5,300,405	36

BLANK

Schedule Page: 422 Line No.: 1 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 2 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 4 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 5 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 6 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 9 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 10 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 11 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 13 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 16 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 18 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 19 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 21 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 23 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 25 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 27 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 30 Column: h
Contains both single and double circuitry.

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Grahamville	DOE 161kv	1.69	SP	6.00	1	
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		1.69		6.00	1	

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
1272mcm			161,000			2,444,040		2,444,040	1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
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									14
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									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
						2,444,040		2,444,040	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	A. O. Smith - Mt. Sterling	Transmission*	69.00	12.47	
2	Adams - Georgetown	Transmission*	138.00	69.00	13.20
3	Alcade - Somerset	Transmission*	345.00	161.00	13.20
4	American Ave. - Lexington	Transmission*	138.00	69.00	13.20
5	Arnold - Cumberland	Transmission*	161.00	69.00	13.20
6	Artemus - Pineville	Transmission*	161.00	69.00	13.20
7	Bardstown- Campellsville	Transmission*	138.00	69.00	13.20
8	Bardstown City- Campbellsville	Transmission*	69.00	12.47	
9	Barlow	Transmission*	69.00	12.47	
10	Beattyville - Richmond	Transmission*	161.00	69.00	13.20
11	Bimble	Transmission*	69.00		
12	Blackwell	Transmission*	138.00		
13	Bond-Coeburn	Transmission*	69.00	12.47	
14	Bonds Mill	Transmission*	69.00		
15	Bonnieville - Horse Cave	Transmission*	138.00	69.00	13.20
16	Boone Ave. - Winchester	Transmission*	69.00	12.47	
17	Boonesboro North - Winchester	Transmission*	138.00	69.00	13.20
18	Boyle County	Transmission*	69.00		
19	Broadhead SW	Transmission*	69.00		
20	Bromley	Transmission*	69.00	12.47	
21	Brown CT - Harrodsburg	Transmission*	138.00		
22	Brown North - Harrodsburg	Transmission*	345.00	138.00	13.20
23	Brown North - Harrodsburg	Transmission*	144.00	24.00	
24	Brown Plant - Harrodsburg	Transmission*	138.00	13.20	
25	Brown Plant - Harrodsburg	Transmission*	138.00	17.10	
26	Carntown - Augusta	Transmission*	138.00	69.00	13.20
27	Carrollton - Carrollton	Transmission*	138.00	69.00	13.20
28	Cary SW	Transmission*	69.00		
29	Clark County - Winchester	Transmission*	138.00	69.00	13.20
30	Clinton	Transmission*	69.00		
31	Coleman Road - McCracken Co	Transmission*	161.00		
32	Corydon - Henderson	Transmission*	161.00	69.00	13.20
33	Crittendon County - Marion	Transmission*	161.00	69.00	13.20
34	Cynthiana SW	Transmission*	69.00		
35	Danville North - Danville	Transmission*	138.00	69.00	13.20
36	Daviess County	Transmission*	345.00		
37	Delvinta	Transmission*	161.00		
38	Dix Dam Plant - Harrodsburg	Transmission*	69.00	13.20	
39	Dow Corning West	Transmission*	138.00		
40	Dorchester - Norton	Transmission*	161.00	69.00	13.20

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
			NONE			1
94	1		NONE			2
448	1		NONE			3
150	1		NONE			4
56	1		NONE			5
56	1		NONE			6
94	1		NONE			7
			NONE			8
			NONE			9
56	1		NONE			10
			NONE			11
			NONE			12
			NONE			13
			NONE			14
34	1		NONE			15
			NONE			16
150	1		NONE			17
			NONE			18
			NONE			19
			NONE			20
			NONE			21
448	1		NONE			22
			NONE			23
			NONE			24
			NONE			25
50	1		NONE			26
187	2		NONE			27
			NONE			28
93	1		NONE			29
			NONE			30
			NONE			31
112	1		NONE			32
112	1		NONE			33
			NONE			34
112	1		NONE			35
			NONE			36
			NONE			37
			NONE			38
			NONE			39
187	2		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Earlington North - Earlington	Transmission*	161.00	69.00	13.20
2	East Frankfort - Frankfort	Transmission*	138.00	69.00	13.20
3	Elihu - Somerset	Transmission*	161.00	69.00	13.20
4	Elizabethtown - Elizabethtown	Transmission*	138.00	69.00	13.20
5	Eminence	Transmission*	69.00		
6	Evarts	Transmission*	69.00		
7	Farley - Corbin	Transmission*	161.00	69.00	13.20
8	Farmers - Morehead	Transmission*	80.00	40.00	13.20
9	Fawkes - Richmond	Transmission*	138.00	69.00	13.20
10	Finchville	Transmission*	69.00		
11	FMC - Lexington	Transmission*	69.00	12.47	
12	Ghent Plant - Carrollton	Transmission*	345.00	138.00	
13	Ghent Plant - Carrollton	Transmission*	345.00	138.00	25.00
14	Goddard	Transmission*	138.00		
15	Gorge SW	Transmission*	69.00		
16	Grahamville - Barlow	Transmission*	161.00	69.00	13.20
17	Green River Plant - Greenville	Transmission*	138.00	69.00	13.20
18	Green River Plant - Greenville	Transmission*	154.00	138.00	13.20
19	Green River Plant - Greenville	Transmission*	161.00	138.00	13.20
20	Green River Steel - Greenville	Transmission*	138.00	69.00	13.20
21	Haefling - Lexington	Transmission*	138.00	69.00	13.20
22	Hardin County - Elizabethtown	Transmission*	345.00	138.00	13.20
23	Hardin County - Elizabethtown	Transmission*	138.00	69.00	13.20
24	Hardinsburg - Hardinsburg	Transmission*	138.00		
25	Harlan "Y" - Harlan	Transmission*	161.00	69.00	13.20
26	Higby Mill - Lexington	Transmission*	138.00	69.00	13.20
27	Hillside	Transmission*	69.00		
28	Howards Branch	Transmission*	161.00		
29	Hughes Lane - Lexington	Transmission*	69.00	12.47	
30	Imboden - Big Stone Gap	Transmission*	161.00	69.00	13.20
31	Indian Hill	Transmission*	69.00		
32	Kenton - Maysville	Transmission*	132.00	69.00	13.20
33	Kenton - Maysville	Transmission*	138.00	69.00	13.20
34	KU Park - Pineville	Transmission*	69.00		
35	LaGrange East	Transmission*	69.00	12.47	
36	Lake Reba - Richmond	Transmission*	138.00	69.00	13.20
37	Lake Reba Tap - Richmond	Transmission*	161.00	138.00	6.60
38	Lancaster	Transmission*	69.00		
39	Lansdowne - Lexington	Transmission*	138.00	69.00	13.20
40	Lebanon - Lebanon	Transmission*	80.00	40.00	13.20

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
224	1	1	NONE			1
224	2		NONE			2
187	2		NONE			3
149	1		NONE			4
			NONE			5
			NONE			6
149	1		NONE			7
40	3		NONE			8
299	2		NONE			9
			NONE			10
			NONE			11
450	1	1	NONE			12
448	1		NONE			13
			NONE			14
			NONE			15
93	1		NONE			16
261	2		NONE			17
200	2		NONE			18
112	1		NONE			19
93	1		NONE			20
149	1		NONE			21
448	1		NONE			22
149	1		NONE			23
			NONE			24
94	1		NONE			25
344	3	1	NONE			26
			NONE			27
			NONE			28
			NONE			29
149	1		NONE			30
			NONE			31
33	1	1	NONE			32
112	1		NONE			33
		1	NONE			34
			NONE			35
149	1		NONE			36
200	1		NONE			37
			NONE			38
112	1		NONE			39
100	6		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Lebanon City	Transmission*	69.00	12.47	
2	Leitchfield - Leitchfield	Transmission*	138.00	69.00	13.20
3	Leitchfield East	Transmission*	69.00	12.47	
4	Lexington Plant - Lexington	Transmission*	69.00		
5	Livingston County	Transmission*	161.00		
6	London - London	Transmission*	69.00		
7	Loudon Ave - Lexington	Transmission*	138.00	69.00	13.20
8	Lynch - Harlan	Transmission*	69.00		
9	Manchester	Transmission*	69.00	12.47	
10	Marion	Transmission*	69.00		
11	Meldrum SW	Transmission*	69.00		
12	Middlesboro - Middlesboro	Transmission*	69.00		
13	Millersburg - Millersburg	Transmission*	69.00		
14	Morganfield - Morganfield	Transmission*	161.00	69.00	13.20
15	Mt. Vernon - Mt. Vernon	Transmission*	69.00		
16	N.A.S.	Transmission*	345.00	138.00	
17	Nebo - Nebo	Transmission*	69.00		
18	North London -London	Transmission*	69.00		
19	North Princeton - Princeton	Transmission*	161.00		
20	Ohio County - Beaver Dam	Transmission*	138.00	69.00	13.20
21	Paducah Primary - Paducah	Transmission*	161.00		
22	Paris	Transmission*	138.00	69.00	13.20
23	Pineville - Pineville	Transmission*	345.00	161.00	13.20
24	Pineville - Pineville	Transmission*	500.00	345.00	34.50
25	Pineville - Pineville	Transmission*	161.00	69.00	13.20
26	Pineville SW - Pineville	Transmission*	161.00		
27	Pisgah - Lexington	Transmission*	138.00	69.00	13.20
28	Pittsburg - London	Transmission*	161.00	69.00	13.20
29	Pocket - Pennington Gap	Transmission*	161.00	69.00	13.20
30	Pocket North - Pennington Gap	Transmission*	500.00	161.00	
31	Princeton - Princeton	Transmission*	69.00		
32	Richmond - Richmond	Transmission*	69.00		
33	River Queen - Muhlenberg	Transmission*	161.00	69.00	13.20
34	Rocky Branch	Transmission*	69.00		
35	Rodburn - Morehead	Transmission*	138.00	69.00	13.20
36	Rogersville - Radcliff	Transmission*	138.00	69.00	13.20
37	Scott County	Transmission*	138.00	69.00	13.20
38	Shelbyville - Shelbyville	Transmission*	69.00		
39	Simmons	Transmission*	69.00		
40	Somerset N - Somerset	Transmission*	69.00		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
			NONE			1
93	1		NONE			2
			NONE			3
			NONE			4
			NONE			5
			NONE			6
262	2	1	NONE			7
			NONE			8
			NONE			9
			NONE			10
			NONE			11
			NONE			12
			NONE			13
112	1		NONE			14
			NONE			15
450	1		NONE			16
			NONE			17
			NONE			18
			NONE			19
93	1	3	NONE			20
		3	NONE			21
150	1		NONE			22
560	1		NONE			23
504	1		NONE			24
243	2		NONE			25
			NONE			26
112	1		NONE			27
112	1		NONE			28
187	1		NONE			29
448	1		NONE			30
			NONE			31
			NONE			32
			NONE			33
			NONE			34
61	1		NONE			35
93	1		NONE			36
93	1		NONE			37
			NONE			38
			NONE			39
			NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	South Paducah	Transmission*	161.00	69.00	13.20
2	Spears SW	Transmission*	69.00		
3	Spencer Road - Mt. Sterling	Transmission*	138.00	69.00	13.20
4	St. Paul	Transmission*	69.00	12.47	
5	Sweet Hollow	Transmission*	69.00		
6	Taylor County - Campellsville	Transmission*	161.00	69.00	13.20
7	Tyrone - Versailles	Transmission*	138.00	69.00	13.20
8	UK Medical Center - Lexington	Transmission*	69.00		
9	Versailles Bypass - Versailles	Transmission*	69.00	12.47	
10	Virginia City - Norton	Transmission*	138.00	69.00	13.20
11	Walker - Earlington	Transmission*	161.00	69.00	13.20
12	West Cliff - Harrodsburg	Transmission*	138.00	69.00	13.20
13	West Frankfort - Shelbyville	Transmission*	345.00	138.00	13.20
14	West Frankfort - Shelbyville	Transmission*	138.00	69.00	13.20
15	West Garrard - Lancaster	Transmission*	345.00		
16	West Irvine - Irvine	Transmission*	161.00	69.00	13.20
17	West Lexington - Lexington	Transmission*	345.00	138.00	13.20
18	Wheatcroft	Transmission*	69.00		
19	Wickliffe - Barlow	Transmission*	161.00	69.00	13.20
20	Williamsburg SW	Transmission*	69.00		
21	Winchester City	Transmission*	69.00		
22	Wofford	Transmission*	69.00		
23	Total Transmission		19553.00	6394.08	937.30
24					
25	A.O. Smith - Mt. Sterling	Distribution*	69.00	12.47	
26	Adams 12KV	Distribution*	69.00	34.50	
27	Airgas 13.8KV	Distribution*	138.00	13.80	
28	Aisin 12KV	Distribution*	69.00	12.47	
29	Alexander - Versailles	Distribution*	69.00	12.47	
30	American Ave. - Lexington	Distribution*	69.00	4.16	
31	Andover - Norton	Distribution*	69.00	34.50	
32	Ashland Ave. - Lexington	Distribution*	69.00	4.16	
33	Ashland Pipe - Lexington	Distribution*	69.00	12.47	
34	Augusta 12KV	Distribution*	69.00	12.47	
35	Bardstown City 12KV	Distribution*	69.00	12.47	
36	Bardstown Ind. 12KV	Distribution*	69.00	12.47	
37	Beaver Dam - Beaver Dam	Distribution*	69.00	12.47	
38	Beaver Dam North - Beaver Dam	Distribution*	69.00	12.47	
39	Belt Line - Lexington	Distribution*	69.00	12.47	
40	Bevier - Earlington	Distribution*	69.00	34.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
50	1		NONE			1
			NONE			2
89	2		NONE			3
			NONE			4
			NONE			5
90	1		NONE			6
112	1		NONE			7
			NONE			8
			NONE			9
120	1		NONE			10
112	1		NONE			11
392	3		NONE			12
450	1		NONE			13
112	1		NONE			14
			NONE			15
56	1		NONE			16
448	1		NONE			17
			NONE			18
93	1		NONE			19
			NONE			20
			NONE			21
			NONE			22
13104	92	12				23
						24
14	1		NONE			25
43	2		NONE			26
22	1		NONE			27
14	1		NONE			28
22	1		NONE			29
14	1		NONE			30
37	1		NONE			31
28	2		NONE			32
20	2		NONE			33
14	1		NONE			34
23	1		NONE			35
45	2		NONE			36
14	1		NONE			37
14	1		NONE			38
22	1		NONE			39
13	1		NONE			40

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Big Stone Gap - Big Stone Gap	Distribution*	69.00	12.47	
2	Bond - Coeburn	Distribution*	69.00	12.47	
3	Boone Ave. - Winchester	Distribution*	69.00	12.47	
4	Borg Warner - Earlington	Distribution*	69.00	12.47	
5	Bryant Road - Lexington	Distribution*	69.00	12.47	
6	Buchanan - Lexington	Distribution*	69.00	4.16	
7	Buena Vista 12KV	Distribution*	69.00	12.47	
8	Burnside - Somerset	Distribution*	69.00	12.47	
9	Camargo - Mt. Sterling	Distribution*	69.00	12.47	
10	Camp Breckinridge	Distribution*	69.00	12.47	
11	Campbellsville 1 - Campbellsville	Distribution*	69.00	12.47	
12	Campbellsville 2 - Campbellsville	Distribution*	69.00	12.47	
13	Carntown - Augusta	Distribution*	69.00	12.47	
14	Caron - London	Distribution*	69.00	12.47	
15	Carrollton - Carrollton	Distribution*	69.00	12.47	
16	Cawood - Harlan	Distribution*	69.00	12.47	
17	Clay Mills - Lexington	Distribution*	138.00	12.47	
18	Clinch Valley - Norton	Distribution*	69.00	12.47	
19	Columbia - Columbia	Distribution*	69.00	12.47	
20	Columbia South - Columbia	Distribution*	69.00	12.47	
21	Corbin East - Corbin	Distribution*	69.00	12.47	
22	Corning 12KV	Distribution*	69.00	12.47	
23	Corporate Drive 2 - 12KV	Distribution*	69.00	12.47	
24	Cynthiana 12KV	Distribution*	69.00	12.47	
25	Cynthiana South 12KV	Distribution*	67.00	12.47	
26	Danville 1 - Danville	Distribution*	69.00	12.47	
27	Danville East - Danville	Distribution*	69.00	12.47	
28	Danville Ind. - Danville	Distribution*	69.00	12.47	
29	Danville North - Danville	Distribution*	69.00	12.47	
30	Danville West - Danville	Distribution*	69.00	12.47	
31	Dark Hollow - Richmond	Distribution*	69.00	12.47	
32	Dawson Ind. - Earlington	Distribution*	69.00	4.16	
33	Days Branch 12KV	Distribution*	69.00	12.47	
34	Dayton - Walther - Carrollton	Distribution*	138.00	12.47	
35	Delaplain - Georgetown	Distribution*	69.00	13.80	
36	Denham Street - Somerset	Distribution*	69.00	12.47	
37	Detroit Harvester - Paris	Distribution*	69.00	12.47	
38	Donerail - Lexington	Distribution*	69.00	12.47	
39	Dorchester - Norton	Distribution*	69.00	22.00	
40	Dow Corning - Carrollton	Distribution*	69.00	12.47	

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Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
42	3		NONE			1
67	3		NONE			2
23	1		NONE			3
23	1		NONE			4
67	3		NONE			5
14	1		NONE			6
14	1		NONE			7
14	1		NONE			8
28	2		NONE			9
14	1		NONE			10
45	2		NONE			11
23	1		NONE			12
23	1		NONE			13
23	1		NONE			14
14	1		NONE			15
14	1		NONE			16
37	1		NONE			17
23	1		NONE			18
14	1		NONE			19
14	1		NONE			20
37	2		NONE			21
61	5		NONE			22
30	2		NONE			23
20	2		NONE			24
14	1		NONE			25
23	1		NONE			26
23	1		NONE			27
45	2		NONE			28
14	1		NONE			29
23	1		NONE			30
14	1		NONE			31
14	1		NONE			32
14	1		NONE			33
14	1		NONE			34
37	2		NONE			35
14	1		NONE			36
23	1		NONE			37
14	1		NONE			38
56	3		NONE			39
14	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Dozier Heights 12KV	Distribution*	69.00	12.47	
2	Earlington - Earlington	Distribution*	69.00	34.50	
3	East Bernstadt - London	Distribution*	69.00	12.47	
4	East Stone - Big Stone Gap	Distribution*	69.00	12.47	
5	Eastland - Lexington	Distribution*	69.00	12.47	
6	Elizabethtown Industrial - Elizabethtown	Distribution*	69.00	12.47	
7	Eminence - Shelbyville	Distribution*	69.00	12.47	
8	Esserville - Norton	Distribution*	69.00	12.47	
9	Etown #2 - Elizabethtown	Distribution*	69.00	12.47	
10	Etown #3 - Elizabethtown	Distribution*	69.00	12.47	
11	Etown #4 - Elizabethtown	Distribution*	69.00	12.47	
12	Etown #5 East - Elizabethtown	Distribution*	69.00	12.47	
13	Etown West - Elizabethtown	Distribution*	69.00	12.47	
14	Ewington - Mt. Sterling	Distribution*	69.00	12.47	
15	Fairfield - Fairfield	Distribution*	69.00	12.47	
16	Ferguson South - Somerset	Distribution*	69.00	12.47	
17	Florida Tile - Lawrenceburg	Distribution*	69.00	12.47	
18	FMC - Lexington	Distribution*	69.00	12.47	
19	Forks of Elkhorn - Georgetown	Distribution*	34.50	12.47	
20	Frankfort - Frankfort	Distribution*	69.00	34.50	
21	GE Lamp Works - Lexington	Distribution*	69.00	4.16	
22	Georgetown - Georgetown	Distribution*	69.00	12.47	
23	Ghent Scrubbers 12KV	Distribution*	138.00	13.20	
24	Green River Steel 2 12KV	Distribution*	69.00	12.47	
25	Green River 34KV	Distribution*	69.00	34.50	
26	Greensburg - Campellsville	Distribution*	69.00	12.47	
27	Greenville 12KV - Muhlenburg	Distribution*	69.00	12.47	
28	Greenville North - Muhlenburg	Distribution*	69.00	12.47	
29	Haefling - Lexington	Distribution*	138.00	12.47	
30	Haley - Lexington	Distribution*	69.00	12.47	
31	Hamblin - Pennington Gap	Distribution*	69.00	12.47	
32	Hanson - Earlington	Distribution*	69.00	12.47	
33	Hardesty - Earlington	Distribution*	69.00	34.50	
34	Harlan - Harlan	Distribution*	69.00	12.47	
35	Harlan Wye - Harlan	Distribution*	69.00	12.47	
36	Harrodsburg #2 - Harrodsburg	Distribution*	69.00	12.47	
37	Harrodsburg #3 - Harrodsburg	Distribution*	69.00	12.47	
38	Harrodsburg North 12KV	Distribution*	69.00	12.47	
39	Higby Mill 12KV - Lexington	Distribution*	138.00	12.47	
40	Highsplint - Harlan	Distribution*	69.00	12.47	

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
14	1		NONE			1
34	2		NONE			2
14	1		NONE			3
25	2		NONE			4
23	1		NONE			5
23	1		NONE			6
28	2		NONE			7
23	1		NONE			8
45	2		NONE			9
33	2		NONE			10
23	1		NONE			11
14	1		NONE			12
23	1		NONE			13
37	2		NONE			14
14	1		NONE			15
14	1		NONE			16
14	1		NONE			17
23	1		NONE			18
14	1		NONE			19
20	1		NONE			20
14	1		NONE			21
14	1		NONE			22
56	2		NONE			23
14	1		NONE			24
17	1		NONE			25
14	1		NONE			26
14	1		NONE			27
14	1		NONE			28
39	1		NONE			29
14	1		NONE			30
14	1		NONE			31
14	1		NONE			32
13	1		NONE			33
14	1		NONE			34
28	2		NONE			35
14	1		NONE			36
14	1		NONE			37
14	1		NONE			38
60	2		NONE			39
14	1		NONE			40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Hodgenville 12KV	Distribution*	69.00	12.47	
2	Hoover 12KV - Georgetown	Distribution*	69.00	12.47	
3	Hopewell - Corbin	Distribution*	69.00	12.47	
4	Horse Cave 12KV	Distribution*	69.00	12.47	
5	Horse Cave Industrial - Horse Cave	Distribution*	69.00	12.47	
6	Hughes Lane - Lexington	Distribution*	69.00	12.47	
7	IBM - Lexington	Distribution*	69.00	12.47	
8	IBM North 12KV	Distribution*	138.00	12.47	
9	Imboden - Norton	Distribution*	69.00	34.50	
10	Innovation Drive	Distribution*	138.00	12.47	
11	Irvine - Richmond	Distribution*	69.00	12.47	
12	Joyland - Lexington	Distribution*	69.00	12.47	
13	Kawneer - Cynthiana	Distribution*	69.00	12.47	
14	Kenton - Maysville	Distribution*	69.00	12.47	
15	Kentucky River 4KV	Distribution*	69.00	4.16	
16	LaGrange East	Distribution*	69.00	12.47	
17	LaGrange - Penal - LaGrange	Distribution*	69.00	12.47	
18	Lakeshore - Lexington	Distribution*	69.00	12.47	
19	Lancaster - Danville	Distribution*	69.00	4.16	
20	Lansdowne - Lexington	Distribution*	69.00	12.47	
21	Lawrenceburg - Lawrenceburg	Distribution*	69.00	12.47	
22	Lebanon - Lebanon	Distribution*	69.00	12.47	
23	Lebanon East	Distribution*	69.00	12.47	
24	Lebanon South 12KV - Lebanon	Distribution*	69.00	12.47	
25	Lebanon Junction 12KV	Distribution*	69.00	12.47	
26	Lebanon West 12KV	Distribution*	138.00	12.47	
27	Leitchfield 12KV - Leitchfield	Distribution*	69.00	12.47	
28	Leitchfield East - Leitchfield	Distribution*	69.00	12.47	
29	Lemons Mill - Georgetown	Distribution*	69.00	12.47	
30	Lexington Water Company	Distribution*	69.00	12.47	
31	Lexington 4KV - Lexington	Distribution*	69.00	4.16	
32	Liberty - Liberty	Distribution*	69.00	12.47	
33	Liberty Road - Lexington	Distribution*	69.00	12.47	
34	London - London	Distribution*	69.00	12.47	
35	Loudon Ave. - Lexington	Distribution*	138.00	12.47	
36	Madisonville GE 12KV	Distribution*	69.00	12.47	
37	Madisonville HP 12KV	Distribution*	69.00	12.47	
38	Madisonville North 4KV	Distribution*	69.00	4.16	
39	Madisonville West 12KV	Distribution*	69.00	12.47	
40	Madisonville East 12KV	Distribution*	69.00	12.47	

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Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
14	1		NONE			1
23	1		NONE			2
28	2		NONE			3
28	2		NONE			4
45	2		NONE			5
14	1		NONE			6
75	2		NONE			7
34	1		NONE			8
37	1		NONE			9
51	2		NONE			10
14	1		NONE			11
37	2		NONE			12
14	1		NONE			13
28	2		NONE			14
28	2		NONE			15
37	2		NONE			16
23	1		NONE			17
37	1		NONE			18
14	1		NONE			19
75	2		NONE			20
45	2		NONE			21
14	1		NONE			22
14	3		NONE			23
14	1		NONE			24
23	1		NONE			25
14	1		NONE			26
14	1		NONE			27
14	1		NONE			28
45	2		NONE			29
45	2		NONE			30
28	2		NONE			31
14	1		NONE			32
37	1		NONE			33
45	2		NONE			34
37	1		NONE			35
23	1		NONE			36
14	1		NONE			37
23	1		NONE			38
23	1		NONE			39
14	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Manchester South	Distribution*	69.00	12.47	
2	Marion South - Marion	Distribution*	69.00	12.47	
3	Maysville Mid - Maysville	Distribution*	69.00	4.16	
4	McCoy Avenue 12KV	Distribution*	69.00	12.47	
5	McKee Road 12KV	Distribution*	69.00	12.47	
6	Meldrum - Middlesboro	Distribution*	69.00	12.47	
7	Metal & Thermit - Carrollton	Distribution*	69.00	12.47	
8	Middlesboro #1 12KV	Distribution*	69.00	12.47	
9	Middlesboro #2 12KV	Distribution*	69.00	12.47	
10	Midway - Versailles	Distribution*	138.00	12.47	
11	Minor Farm 12KV	Distribution*	69.00	12.47	
12	Morehead - Morehead	Distribution*	69.00	12.47	
13	Morganfield Industrial - Morganfield	Distribution*	69.00	12.47	
14	Mt. Sterling - Mt. Sterling	Distribution*	69.00	12.47	
15	Mt. Vernon - Mt. Vernon	Distribution*	69.00	12.47	
16	Muhlenburg Prison - Muhlenburg	Distribution*	69.00	12.47	
17	Newtown 12KV	Distribution*	69.00	12.47	
18	Norton East - Norton	Distribution*	69.00	12.47	
19	Nortonville	Distribution*	34.50	12.47	
20	Oakhill - Earlington	Distribution*	69.00	34.50	
21	Okonite - Richmond	Distribution*	69.00	12.47	
22	Owingsville 12KV	Distribution*	69.00	12.47	
23	Oxford - Georgetown	Distribution*	69.00	12.47	
24	Paris - Paris	Distribution*	69.00	12.47	
25	Parker Seal 12KV - Winchester	Distribution*	69.00	12.47	
26	Parkers Mill 12KV	Distribution*	69.00	12.47	
27	Pepper Pike 12KV - Georgetown	Distribution*	34.50	12.47	
28	Picadome 12KV - Lexington	Distribution*	69.00	12.47	
29	Pineville 12KV	Distribution*	69.00	12.47	
30	Pocket - Norton	Distribution*	69.00	34.50	
31	Poor Valley - Pennington Gap	Distribution*	69.00	12.47	
32	Powderly - Muhlenburg	Distribution*	69.00	12.47	
33	Princeton - Princeton	Distribution*	69.00	34.50	
34	Proctor/Gamble 4KV	Distribution*	69.00	4.16	
35	Race Street - Lexington	Distribution*	69.00	12.47	
36	Radcliff - Radcliff	Distribution*	69.00	12.47	
37	Red House 12KV	Distribution*	69.00	12.47	
38	Reynolds - Lexington	Distribution*	138.00	12.47	
39	Richmond 12KV	Distribution*	69.00	12.47	
40	Richmond #3 12KV (EKU)	Distribution*	69.00	12.47	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	1		NONE			1
14	1		NONE			2
14	1		NONE			3
14	1		NONE			4
14	1		NONE			5
14	1		NONE			6
14	1		NONE			7
28	2		NONE			8
28	2		NONE			9
14	1		NONE			10
14	1		NONE			11
14	1		NONE			12
14	1		NONE			13
14	1		NONE			14
14	1		NONE			15
14	1		NONE			16
14	1		NONE			17
14	1		NONE			18
14	1		NONE			19
20	1		NONE			20
14	1		NONE			21
14	1		NONE			22
28	2		NONE			23
14	1		NONE			24
23	1		NONE			25
45	2		NONE			26
14	1		NONE			27
23	1		NONE			28
28	2		NONE			29
20	1		NONE			30
14	1		NONE			31
14	1		NONE			32
13	1		NONE			33
14	1		NONE			34
14	1		NONE			35
23	1		NONE			36
14	1		NONE			37
77	2		NONE			38
45	2		NONE			39
45	2		NONE			40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Richmond East	Distribution*	69.00	12.47	
2	Richmond Industrial	Distribution*	69.00	12.47	
3	Richmond South	Distribution*	69.00	12.47	
4	Rockwell - Winchester	Distribution*	69.00	12.47	
5	Rogers Gap 12KV	Distribution*	69.00	12.47	
6	Rogersville - Radcliff	Distribution*	69.00	12.47	
7	Rumsey - Earlington	Distribution*	34.50	34.50	
8	Salem - Earlington	Distribution*	69.00	34.50	
9	Shannon Run 12KV	Distribution*	69.00	12.47	
10	Sharon - Augusta	Distribution*	69.00	12.47	
11	Shavers Chap 12KV	Distribution*	69.00	12.47	
12	Shelbyville North12KV	Distribution*	69.00	12.47	
13	Shelbyville East	Distribution*	69.00	12.47	
14	Shelbyville South	Distribution*	69.00	12.47	
15	Shun Pike 12KV	Distribution*	69.00	12.47	
16	Simpsonville - Shelbyville	Distribution*	69.00	12.47	
17	Somerset #2 4KV	Distribution*	69.00	4.16	
18	Somerset #3 12KV	Distribution*	69.00	12.47	
19	Somerset South	Distribution*	69.00	12.47	
20	Springfield - Campbellsville	Distribution*	69.00	12.47	
21	St. Paul 12KV	Distribution*	69.00	12.47	
22	Stamping Ground 12KV	Distribution*	34.50	12.47	
23	Stanford 12KV	Distribution*	69.00	12.47	
24	Stanford North 12KV	Distribution*	69.00	12.47	
25	Stonewall 12KV - Lexington	Distribution*	69.00	12.47	
26	Sylvania 12KV - Winchester	Distribution*	69.00	12.47	
27	Taylorsville - Shelbyville	Distribution*	69.00	12.47	
28	Toyota North	Distribution*	138.00	13.20	
29	Toyota South	Distribution*	138.00	13.20	
30	Trafton Ave. 12KV - Lexington	Distribution*	69.00	12.47	
31	Trafton Ave. 4KV - Lexington	Distribution*	69.00	4.16	
32	UK Scott 12KV	Distribution*	69.00	12.47	
33	UK Medical Center - Lexington	Distribution*	69.00	12.47	
34	UK West - Lexington	Distribution*	69.00	13.09	
35	Union Underwear - Russell Springs	Distribution*	69.00	12.47	
36	Vaksdahl Avenue 12KV	Distribution*	69.00	12.47	
37	Verda - Harlan	Distribution*	69.00	12.47	
38	Versailles West 12KV - Versailles	Distribution*	69.00	12.47	
39	Versailles Bypass - Versailles	Distribution*	69.00	12.47	
40	Viley Road - Lexington	Distribution*	138.00	12.47	

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
23	1		NONE			1
23	1		NONE			2
23	1		NONE			3
23	1		NONE			4
23	1		NONE			5
23	1		NONE			6
13	1		NONE			7
14	1		NONE			8
14	1		NONE			9
14	1		NONE			10
14	1		NONE			11
23	1		NONE			12
23	1		NONE			13
37	2		NONE			14
14	1		NONE			15
14	1		NONE			16
14	1		NONE			17
14	1		NONE			18
14	1		NONE			19
14	1		NONE			20
45	2		NONE			21
14	1		NONE			22
14	1		NONE			23
14	1		NONE			24
37	1		NONE			25
23	1		NONE			26
14	1		NONE			27
84	3		NONE			28
84	3		NONE			29
23	1		NONE			30
14	1		NONE			31
37	1		NONE			32
75	2		NONE			33
14	1		NONE			34
28	2		NONE			35
14	1		NONE			36
14	1		NONE			37
23	1		NONE			38
45	2		NONE			39
39	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Vine Street 12KV - Lexington	Distribution*	69.00	12.47	
2	Waitsboro - Somerset	Distribution*	69.00	12.47	
3	Warsaw East - Owenton	Distribution*	69.00	12.47	
4	West Hickman - Lexington	Distribution*	69.00	12.47	
5	West High Street 12KV - Lexington	Distribution*	69.00	12.47	
6	Westvaco 13.8KV	Distribution*	69.00	13.80	
7	Wickliffe 13.8KV	Distribution*	69.00	13.80	
8	Wilson Downing - Lexington	Distribution*	69.00	12.47	
9	Williamsburg South - Williamsburg	Distribution*	69.00	12.47	
10	Wilmore - Versailles	Distribution*	69.00	12.47	
11	Winchester Industrial 12KV - Winchester	Distribution*	69.00	12.47	
12	Winchester WW 12KV	Distribution*	69.00	12.47	
13	Wise - Norton	Distribution*	69.00	12.47	
14	Woodlawn 12KV	Distribution*	69.00	12.47	
15	248 Stations Less Than 10,000 KVA				
16					
17	Total Distribution		16730.50	3064.12	
18					
19	* Unattended				
20					
21					
22	Summary				
23	Transmission 133				
24	Distribution 478				
25	Total 611				
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	1		NONE			1
14	1		NONE			2
14	1		NONE			3
23	1		NONE			4
28	2		NONE			5
67	3		NONE			6
14	1		NONE			7
45	2		NONE			8
14	1		NONE			9
14	1		NONE			10
23	1		NONE			11
14	1		NONE			12
23	1		NONE			13
14	1		NONE			14
1564	357		NONE			15
						16
7146	657					17
						18
						19
						20
						21
						22
13104	92	12				23
7146	657					24
20250	749	12				25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Capital Expenditures	Louisville Gas and Electric Company	see footnote	9,109,219
3	Direct-Indirect Labor	Louisville Gas and Electric Company	see footnote	8,063,903
4	Equipment and Facilities	Louisville Gas and Electric Company	see footnote	2,921,528
5	Office and Administrative Services	Louisville Gas and Electric Company	see footnote	51,631
6	Materials and Fuels	Louisville Gas and Electric Company	see footnote	64,345,076
7	Outside Services	Louisville Gas and Electric Company	see footnote	1,557,152
8				
9	Capital Expenditures	LG&E and KU Services Company	see footnote	30,117,214
10	Direct-Indirect Labor	LG&E and KU Services Company	see footnote	90,502,316
11	Equipment and Facilities	LG&E and KU Services Company	see footnote	8,593,510
12	Office and Administrative Services	LG&E and KU Services Company	see footnote	6,887,546
13	Materials and Fuels	LG&E and KU Services Company	see footnote	989,296
14	Outside Services	LG&E and KU Services Company	see footnote	20,939,224
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Capital Expenditures	Louisville Gas and Electric Company	see footnote	14,115,961
22	Direct-Indirect Labor	Louisville Gas and Electric Company	see footnote	1,893,915
23	Equipment and Facilities	Louisville Gas and Electric Company	see footnote	342,918
24	Office and Administrative Services	Louisville Gas and Electric Company	see footnote	1,148,514
25	Materials and Fuels	Louisville Gas and Electric Company	see footnote	1,952,080
26	Outside Services	Louisville Gas and Electric Company	see footnote	547,014
27				
28	Capital Expenditures	LG&E and KU Services Company	see footnote	1,627
29	Direct-Indirect Labor	LG&E and KU Services Company	see footnote	1,043,549
30	Office and Administrative Services	LG&E and KU Services Company	see footnote	155,221
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	see footnote for allocation process			

Schedule Page: 429 Line No.: 2 Column: c
Accounts charged include: 107 and 108

Schedule Page: 429 Line No.: 3 Column: c
Accounts charged include: 143, 163, 183, 184, 236, 408, 426, 500-502, 505, 506, 510-514, 535, 539, 541, 542, 544-546, 548, 549, 551-554, 556, 560-562, 566, 570, 571, 573, 580, 582-584, 586, 588, 590, 592-595, 598, 901-903, 905, 908, 920, 925, 926 and 935

Schedule Page: 429 Line No.: 4 Column: c
Accounts charged include: 143, 151, 163, 184, 186, 236, 426, 500-502, 505, 506, 510-514, 548, 550-554, 556, 560-563, 566, 570, 571, 573, 580, 584, 586, 588, 592, 593, 595, 598, 901-903, 905, 907, 921, 925, 930, 931 and 935

Schedule Page: 429 Line No.: 5 Column: c
Accounts charged include: 143, 151, 154, 158, 232, 244, 426, 454, 500-502, 506, 509-514, 548-554, 560-562, 566, 567, 580, 582-584, 586, 588, 592, 598, 902, 903, 920, 921 and 935

Schedule Page: 429 Line No.: 6 Column: c
Accounts charged include: 143, 151, 154, 163, 184, 232, 236, 500-502, 506, 510-514, 542, 544, 547, 548, 550, 552-554, 570, 571, 582, 583, 588, 592, 593 and 921

Schedule Page: 429 Line No.: 7 Column: c
Accounts charged include: 143, 184, 500-502, 505, 506, 510-514, 548, 552-554, 566, 570, 571, 584, 901, 921, 928 and 930

Schedule Page: 429 Line No.: 9 Column: c
Accounts charged include: 107 and 108

Schedule Page: 429 Line No.: 10 Column: c
Accounts charged include: 143, 163, 183, 184, 186, 232, 408, 426, 500-502, 510-513, 556, 560, 561, 563, 566, 570, 571, 573, 580, 581, 586, 588, 590, 592, 593, 598, 901-903, 905, 907, 908, 920, 921, 925, 926, 930 and 935

Schedule Page: 429 Line No.: 11 Column: c
Accounts charged include: 163, 165, 183, 184, 421, 426, 500-502, 506, 510, 513, 514, 556, 560, 561, 563, 566, 570, 580, 586, 588, 901-903, 905, 908-910, 921, 925, 928, 930 and 935

Schedule Page: 429 Line No.: 12 Column: c
Accounts charged include: 143, 181-184, 186, 232, 242, 426, 428, 500-502, 506, 510-514, 549, 556, 560, 561, 563, 566, 570, 571, 573, 580, 583, 586, 588, 590, 592, 593, 598, 901-903, 905, 907, 908, 910, 920, 921, 925, 928, 930 and 935

Schedule Page: 429 Line No.: 13 Column: c
Accounts charged include: 163, 184, 236, 426, 500-502, 506, 510, 511, 513, 514, 556, 560, 561, 563, 566, 570, 573, 580, 583, 588, 593, 901, 903, 905, 907, 908, 921, 923, 928, 930 and 935

Schedule Page: 429 Line No.: 14 Column: c
Accounts charged include: 163, 165, 182-184, 186, 242, 253, 426, 456, 500-502, 506, 510, 513, 551, 554, 556, 560, 561, 566, 573, 580, 583, 584, 586, 588, 592, 593, 598, 901, 903, 905, 908-910, 921, 923, 925, 928, 930 and 935

Schedule Page: 429 Line No.: 21 Column: c
Accounts charged include: 107 and 108

Schedule Page: 429 Line No.: 22 Column: c
Accounts charged include: 143, 163, 183, 184, 186, 228, 232, 236, 242, 408, 426, 500-502, 505, 506, 510-514, 535, 538, 539, 542-544, 546, 548, 549, 551-554, 556, 560-562, 566, 570, 580, 582-584, 586, 588, 590, 592-596, 598, 901-903, 905, 908, 920, 925, 926 and 935

Schedule Page: 429 Line No.: 23 Column: c
Accounts charged include: 184, 186, 426, 500-502, 506, 510, 512, 513, 541, 544, 546, 548-554, 560-563, 566, 570, 571, 573, 580-583, 586, 588, 592-594, 598, 901, 903, 905, 907, 921, 925, 930 and 935

Schedule Page: 429 Line No.: 24 Column: c
Accounts charged include: 158, 184, 232, 426, 500-502, 506, 510, 549, 566, 570, 580, 588, 593, 598, 903, 905, 921 and 930

Schedule Page: 429 Line No.: 25 Column: c
Accounts charged include: 142, 154, 163, 501, 502, 506, 511-514, 542, 544, 546-549,

552-554, 562, 570, 571, 580, 582, 588, 593, 594, 598 and 921

Schedule Page: 429 Line No.: 26 Column: c

Accounts charged include: 163, 184, 500-502, 506, 511-513, 542, 548, 552-554, 560, 562, 570, 571, 586, 593, 921 and 923

Schedule Page: 429 Line No.: 28 Column: c

Accounts charged include: 107

Schedule Page: 429 Line No.: 29 Column: c

Accounts charged include: 146, 184, 228, 232, 234 and 236

Schedule Page: 429 Line No.: 30 Column: c

Accounts charged include: 143, 232, 234 and 419

Schedule Page: 429 Line No.: 42 Column: a

Costs between Louisville Gas and Electric Company and Kentucky Utilities Company are charged directly and are not allocated.

LG&E and KU Services Company (Servco) will allocate the costs of service among the affiliated companies using one of several methods that most accurately distributes the costs. The method of cost allocation varies based on the department rendering the service. Any of the methods may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes in the business, but are generally determined annually. The assignment methods used by Servco are as follows:

Contract Ratio – Based on the sum of the physical amount (i.e. tons of coal, cubic feet of natural gas) of the contract for both coal and natural gas for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Departmental Charge Ratio – A specific Servco department ratio based upon various factors. The departmental charge ratio typically applies to indirectly attributable costs such as departmental administrative, support, and/or material and supply costs that benefit more than one affiliate and that require allocation using general measures of cost causation. Methods for assignment are department-specific depending on the type of service being performed and are documented and monitored by the Budget Coordinators for each department. The numerator and denominator vary by department. The ratio is based upon various factors such as labor hours, labor dollars, departmental or entity headcount, capital expenditures, operations & maintenance costs, retail energy sales, charitable contributions, generating plant sites, average allocation of direct reports, net book value of utility plant, total line of business assets, electric capital expenditures, substation assets and transformer assets. These ratios are calculated on an annual basis. Any changes in these ratios will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in any of these ratios from that used in the prior year.

Electric Peak Load Ratio – Based on the sum of the monthly electric maximum system demands for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company and the denominator of which is for all operating companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Energy Marketing Ratio – Based on the absolute value of megawatt hours purchased and sold for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affiliate and the denominator of which is for all operating companies and affected affiliate companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Generation Ratio – Based on the annual forecast of megawatt hours, the numerator of which is for an operating company or an affiliate and the denominator of which is for all operating companies and affected affiliate companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Non-Fuel Material and Services Expenditures – Based on non-fuel material and services expenditures, net of reimbursements, for the immediately preceding twelve consecutive calendar months. The numerator is equal to such expenditures for a specific entity and/or line-of-business as appropriate and the denominator is equal to such expenditures for all applicable entities. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Number of Customers Ratio – Based on the number of retail electric and/or gas customers. This ratio will be determined based on the actual number of customers at the end of the previous calendar year. In some cases, the ratio may be calculated based on the type of customer class being served (i.e. Residential, Commercial or Industrial). The numerator is the total number of each Company's retail customers. The denominator is the total number of retail customers for both KU and LG&E. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Number of Employees Ratio – Based on the number of employees benefiting from the performance of a service. This ratio will be determined based on actual counts of applicable employees at the end of the previous calendar year. A two-step assignment methodology is utilized to properly allocate Servco employee costs to the proper legal entity. The numerator for the first step of this ratio is the total number of employees for each specific company, and the denominator is the total number of employees for all companies in which an allocator is assigned (i.e. KU, LG&E and Servco). For the second step, the ratio of Servco to total employees will then be allocated to the other companies (KU, LG&E and LKC) based on each company's ratio of labor dollars to total labor dollars. (LKC has no employees, but non-utility related labor is charged to it.) This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Number of Meters Ratio – Based on the number or types of meters being utilized by all levels of customer classes within the system for the immediately preceding twelve consecutive calendar months. The numerator is equal to the number of meters for each utility and the denominator is equal to the total meters for KU and LG&E. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Number of Transactions Ratio – Based on the sum of transactions occurring in the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. For example, services pertaining to Materials Logistics would define the transaction as the number of items ordered, picked and disbursed out of the warehouse. Services pertaining to Accounts Payable would define the transaction as the number of invoices processed. The Controller's organization is responsible for maintaining and monitoring specific product/service methodology documentation for actual transactions related to Servco billings. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Project Ratio – Based on the total costs for any departmental or affiliate project for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Retail Revenue Ratio – Based on utility revenues, excluding energy marketing revenues, for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affiliate and the denominator of which is for all operating companies and affected affiliate companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Revenue Ratio – Based on the sum of the revenue for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Revenue, Total Assets and Number of Employees Ratio – Based on an average of the revenue, total assets and number of employees ratios. This ratio is independently calculated for KU and LG&E. The numerator is the sum of Revenue Ratio, Total Assets Ratio and Number of Employees Ratio for the specific company. The denominator is three – the number of ratios being averaged. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Total Assets Ratio – Based on the total assets at year end for the preceding year. In the event of joint ownership of a specific asset, asset ownership percentages are utilized to assign costs. The numerator is the total assets for each specific company at the end of the preceding year. The denominator is the sum of total assets for each company in which an allocator is assigned (KU, LG&E and LKC). This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Total Utility Plant Assets Ratio – Based on the total utility plant assets at year end for the preceding year, the numerator of which is for an operating company or affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. In the event of joint ownership of a specific asset, ownership percentages are utilized to assign costs. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Transportation Resource Management System Chargeback Ratio – Based on the costs associated with providing and operating transportation fleet for all affiliated companies including developing fleet policy, administering regulatory compliance programs, managing repair and maintenance of vehicles and procuring vehicles. Such rates are applied based on the specific equipment employment and the measured usage of services by the various company entities. This ratio is calculated monthly based on the actual transportation charges from the previous month. The numerator is the department labor charged to a specific company. The denominator is the total labor costs for the specific department. The ratio is then multiplied by the total transportation costs to determine the amount charged to each company.

Utility Ownership Percentages – Based on the contractual ownership percentages of jointly-owned generating units. This ratio is updated as a result of a new jointly-owned generating unit, and is based on the total forecasted energy needs. The numerator is the specific company's forecasted incremental capacity and/or energy needs. The denominator is the total incremental capacity and/or energy needs of all companies.

INDEX

Schedule | **Page No.**

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(n)
Sponsoring Witness: Shannon L. Charnas

Description of Filing Requirement:

A summary of the utility's latest depreciation study with schedules by major plant accounts, except that telecommunications utilities that have adopted the commission's average depreciation rates shall provide a schedule that identifies the current and test period depreciation rates used by major plant accounts. If the required information has been filed in another commission case a reference to that case's number and style will be sufficient.

Response:

A copy of KU's latest depreciation study is already on file with the Commission in KU's consolidated depreciation case, Case No. 2007-00565, *In the Matter of: Application of Kentucky Utilities Company to File Depreciation Study*, and rate case, Case No. 2008-00251, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*, and is incorporated by reference herein. As part of this current rate case application, KU is filing a new depreciation study, as referenced in the testimony and exhibits of John J. Spanos.

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(o)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

A list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and work papers associated with the filing of the utility's application. This list shall include each software, program, or model; what the software, program, or model was used for; identify the supplier of each software, program, or model; a brief description of the software, program, or model; the specifications for the computer hardware and the operating system required to run the program.

Response:

See attached.

Supplier	Microsoft	Microsoft	Microsoft	Gannett Fleming, Inc.	Adobe
Software/Program/Model	Word 2007 Word 2010	Excel 2007 Excel 2010	PowerPoint 2007 PowerPoint 2010	Proprietary Model prepared by Gannett Fleming, Inc.	Acrobat Pro Version 9.4.4 Adobe Reader X 10.1.2
Use in Application	Tabs: Statutory Notice, Application, Financial Exhibit, Table of Contents and 1-46	Various attachments including Tabs: Financial Exhibit, 21, 27, 28, 29, 39, 42 and 45	Tab: 21	Tab: 21, 33	Tabs: Statutory Notice, Application, Financial Exhibit, Table of Contents and 1-46
Description	Word processing program	Spreadsheet and graphing program	Presentation program	Prepare the depreciation study	Preserve and secure the layout of documents created in other applications
Hardware Specifications	Intel 2 GHz processor or greater	Intel 2 GHz processor or greater	Intel 2 GHz processor or greater	Personal or multimedia computer with 4 Gig RAM	Intel 2 GHz processor or greater
Operating System Specifications	Windows XP or Windows 7	Windows XP or Windows 7	Windows XP or Windows 7	Microsoft Office XP Pro, Windows 7	Windows XP or Windows 7

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(p)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

Prospectuses of the most recent stock or bond offerings.

Response:

See attached.

Supplement, dated May 2, 2011 to Reoffering Circular dated December 11, 2008, as supplemented as of December 16, 2008, October 29, 2010 and December 1, 2010 (the "Reoffering Circular")

$54,000,000 **County of Carroll, Kentucky** **Environmental Facilities Revenue Refunding Bonds, 2006 Series B** **(Kentucky Utilities Company Project)**	**$77,947,405** **County of Carroll, Kentucky** **Environmental Facilities Revenue Bonds,** **2008 Series A** **(Kentucky Utilities Company Project)**

Effective as of May 2, 2011, through April 22, 2014 (the Letter of Credit (as defined below) expiration date, subject to extension or earlier termination), payment of the principal of and interest on each series of the above-referenced bonds (individually, the "2006 Series B Bonds" and the "2008 Series A Bonds" and, collectively, the "Bonds") when due will be paid with funds drawn under an irrevocable transferable direct pay letter of credit (the "Letter of Credit") issued by

SUMITOMO MITSUI BANKING CORPORATION, NEW YORK BRANCH

The Letter of Credit will permit the Trustee to draw with respect to each series of Bonds up to an amount sufficient to pay (i) the principal of such series of Bonds (or that portion of the purchase price corresponding to principal) plus (ii) interest thereon (or that portion of the purchase price corresponding to interest) up to a maximum rate of 15% per annum for at least 45 days.

Each series of Bonds will continue to bear interest at a Weekly Rate, determined by the Remarketing Agent, BofA Merrill Lynch, in accordance with the Indenture, payable on the first Business Day of each calendar month, commencing on June 1, 2011. The interest rate period, interest rate and Interest Rate Mode for each series of Bonds will be subject to change under certain conditions, as described in the Reoffering Circular. The Bonds of each series are subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption following a determination of taxability prior to maturity, as described in the Reoffering Circular. The Bonds of each series are subject to mandatory purchase on any date on which the Bonds are converted to a different Interest Rate Mode and upon the expiration of the Letter of Credit or any Alternate Credit Facility.

This supplement contains a description of the Letter of Credit and Sumitomo Mitsui Banking Corporation, New York Branch, the issuer of the Letter of Credit. For purposes of the Reoffering Circular, the Letter of Credit is a "Credit Facility" and Sumitomo Mitsui Banking Corporation, New York Branch is a "Credit Facility Issuer." Except as otherwise specified herein, information in the Reoffering Circular referred to above has not been amended or modified and the information contained herein is qualified by reference to, and should be read in conjunction with, the Reoffering Circular, including information incorporated therein by reference. Terms not otherwise defined herein shall have the meanings ascribed to them in such Reoffering Circular.

The eighth paragraph under the section of the Reoffering Circular captioned "Introductory Statement" is hereby amended to read in its entirety as follows:

Effective May 2, 2011, the Company will cause to be delivered separate irrevocable transferable direct pay letters of credit (the "Letters of Credit") with respect to each of the 2006 Series B Bonds and the 2008 Series A Bonds, issued by Sumitomo Mitsui Banking Corporation, New York Branch (the "Bank"), to provide for the timely payment of principal of and accrued interest (calculated for at least 45 days at the maximum rate of 15% per annum) on, and purchase price of, the Bonds. The Company will be required to reimburse the Bank for all amounts drawn by the Trustee under the Letters of Credit pursuant to the terms of separate Reimbursement Agreements, to be dated as of May 2, 2011 (collectively, the "Reimbursement Agreement"), with respect to each of the 2006 Series B Bonds and the 2008 Series A Bonds, between the Company and the Bank. Each Letter of Credit will expire on April 22, 2014 unless extended or earlier terminated.

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The section of the Reoffering Circular captioned "The Letter of Credit" is hereby amended to read in its entirety as follows:

THE LETTER OF CREDIT

The following summarizes certain provisions of the Letter of Credit and the Reimbursement Agreement, to which reference is made for the detailed provisions thereof. Unless otherwise defined in this Reoffering Circular, capitalized terms in the following summary are used as defined in the Letter of Credit and the Reimbursement Agreement. The Company is permitted under the Indenture to deliver an Alternate Credit Facility to replace the Letter of Credit. Any such Alternate Credit Facility must meet certain requirements described in the Indenture.

The Letter of Credit

The Letter of Credit will be an irrevocable transferable direct pay letter of credit issued by the Bank in order to provide additional security for the payment of principal of, purchase price of, interest on and premium, if applicable, on any date when payments under the Bonds are due, including principal and interest payments and payments upon tender, redemption, acceleration or maturity of the Bonds. The Letter of Credit will provide for direct payments to or upon the order of the Trustee as set forth in the Letter of Credit in amounts sufficient to pay such amounts in accordance with the terms thereof.

The Letter of Credit will be issued in an amount equal to the aggregate principal amount of the outstanding Bonds, plus an amount that represents interest accrued thereon at an assumed maximum rate of 15% per annum for 45 days (the "Credit Amount"). The Trustee, upon compliance with the terms of the Letter of Credit, is authorized to draw up to (a) an amount sufficient (i) to pay principal of the Bonds, when due, whether at maturity or upon redemption or acceleration, and (ii) to pay the portion of the purchase price of the Bonds delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed (a "Liquidity Drawing") equal to the principal amount of the Bonds, plus (b) an amount not to exceed 45 days of accrued interest on the Bonds at an assumed rate of 15% per annum (i) to pay interest on the Bonds, when due, and (ii) to pay the portion of the interest accrued on the Bonds as of any Liquidity Drawing.

The amount available under the Letter of Credit will be automatically reduced by the amount of any drawing thereunder, subject to reinstatement as described below. With respect to a drawing by the Trustee solely to pay interest on the Bonds on an Interest Payment Date, the amount available under the Letter of Credit will be automatically reinstated in the amount of such drawing effective on the earlier of (i) receipt by the Bank from the Company of reimbursement of any drawing solely to pay interest in full or (ii) at the opening of business on the eleventh calendar day after the date the Bank honors such drawing, unless the Trustee has received written notice from the Bank by the tenth calendar day after the date the Bank honors such drawing that the Bank is not so reinstating the available amount due to the Company's failure to reimburse the Bank for such drawing in full, or that an event of default has occurred and is continuing under the $198,309,583.05 Letter of Credit Agreement dated as of April 29, 2011 among the Company, the lenders from time to time thereto, and Banco Bilbao Vizcaya Argentaria, S.A., New York Branch, as Administrative Agent (the "Credit Agreement") and, in either case, directing an acceleration of the Bonds pursuant to the Indenture. With respect to a Liquidity Drawing under the Letter of Credit, the amount available under the Letter of Credit will be automatically reduced by the principal amount of the Bonds purchased with the proceeds of such drawing plus the amount of accrued interest on such Bonds. In the event of the remarketing of the Bonds purchased with the proceeds of a Liquidity Drawing, the amount available under the Letter of Credit will be automatically reinstated upon receipt by the Bank or the Trustee on the Bank's behalf of an amount equal to such principal amount plus accrued interest.

The Letter of Credit will terminate on the earliest to occur of:

(i) the Bank's close of business on April 22, 2014 (such date, as extended from time to time in accordance with the Letter of Credit is defined as the "Stated Expiration Date");

(ii) the Bank's close of business on the date which is five Business Days following the date of receipt by the Bank of a certificate from the Trustee certifying that (a) no Bonds remain Outstanding within the meaning of the Indenture, (b) all drawings required to be made under the Indenture and available under the Letter of Credit have been made and honored, (c) an Alternate Credit Facility has been delivered to the Trustee in accordance with the Indenture to replace the Letter of Credit or (d) all of the outstanding Bonds were converted to Bonds bearing interest at a rate other than the Daily Rate or the Weekly Rate;

(iii) the Bank's close of business on the date of receipt by the Bank of a certificate from the Trustee confirming that the Trustee is required to terminate the Letter of Credit in accordance with the terms of the Indenture;

(iv) the date on which the Bank receives and honors an acceleration drawing certificate; or

(v) the Bank's close of business on the date which is 30 days after receipt by the Trustee of written notice from the Bank of an Event of Default under the Credit Agreement and instructing the Trustee to draw under the Letter of Credit.

Pursuant to the Credit Agreement, the Company is obligated to reimburse the Bank for all amounts drawn under the Letter of Credit, and to pay interest on all such amounts. The Company has also agreed to pay the Bank and the Administrative Agent fees for issuing and maintaining the Letter of Credit.

The Reimbursement Agreement

The Reimbursement Agreement, through incorporation of the terms of the Credit Agreement, imposes various covenants and agreements, including various financial and operating covenants, on the Company. Such covenants include, but are not limited to, covenants relating to (i) inspection of the books and financial records of the Company; (ii) mergers or consolidations; (iii) disposition of assets and (iv) capitalization ratios. Any such covenants may be amended, waived or modified at any time by the Bank and without the consent of the Trustee or the holders of the Bonds. Under certain circumstances, the failure of the Company to comply with such covenants may result in a mandatory tender or acceleration of the Bonds.

An Event of Default under the Credit Agreement will constitute an Event of Default under the Reimbursement Agreement. The following events will constitute an Event of Default under the Credit Agreement:

(i) the Company shall fail to pay when due any principal on any Reimbursement Obligations; or

(ii) the Company shall fail to pay when due any interest on the Reimbursement Obligations, any fee or any other amount payable under the Credit Agreement or under any other Loan Document for five (5) days following the date such payment becomes due thereunder; or

(iii) the Company shall fail to observe or perform certain covenants or agreements contained in the Credit Agreement, including those related to mergers, disposition of assets and capitalization ratios; or

(iv) the Company shall fail to give notice of a Default or Event of Default under the Credit Agreement within a specified number of days following knowledge of such occurrence; or

(v) the Company shall fail to observe or perform any covenant or agreement contained in the Credit Agreement or any other Loan Document (other than those covered above) for thirty (30) days after written notice thereof has been given to the defaulting party by the administrative agent, or at the request of the required lenders; or

(vi) any representation, warranty or certification made by the Company in the Credit Agreement or any other Loan Document or in any certificate, financial statement or other document delivered pursuant hereto or thereto shall prove to have been incorrect in any material respect when made or deemed made; or

(vii) the Company shall (i) fail to pay any principal or interest, regardless of amount, due in respect of any Material Debt beyond any period of grace provided with respect thereto, or (ii) fail to observe or perform any other term, covenant, condition or agreement contained in any agreement or instrument evidencing or governing any such Material Debt beyond any period of grace provided with respect thereto if the effect of any failure referred to in this clause (ii) is to cause, or to permit the holder or holders of such Material Debt or a trustee on its or their behalf to cause, such Material Debt to become due prior to its stated maturity; or

(viii) the Company shall commence a voluntary case or other proceeding seeking liquidation, reorganization or other relief with respect to itself or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any substantial part of its property, or shall consent to any such relief or to the appointment of or taking possession by any such official in an involuntary case or other proceeding commenced against it, or shall make a general assignment for the benefit of creditors, or shall fail generally to pay, or shall admit in writing its inability to pay, its debts as they become due, or shall take any corporate action to authorize any of the foregoing; or

(ix) an involuntary case or other proceeding shall be commenced against the Company seeking liquidation, reorganization or other relief with respect to it or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any substantial part of its property, and such involuntary case or other proceeding shall remain undismissed and unstayed for a period of 60 days; or an order for relief shall be entered against the Company under the Bankruptcy Code; or

(x) any member of the ERISA Group shall fail to pay when due an amount or amounts aggregating in excess of $50,000,000 which it shall have become liable to pay under Title IV of ERISA; or notice of intent to terminate a Material Plan shall be filed under Title IV of ERISA by any member of the ERISA Group, any plan administrator or any combination of the foregoing; or the PBGC shall institute proceedings under Title IV of ERISA to terminate, to impose liability (other than for premiums under Section 4007 of ERISA) in respect of, or to cause a trustee to be appointed to administer any Material Plan; or a condition shall exist by reason of which the PBGC would be entitled to obtain a decree adjudicating that any Material Plan must be terminated; or there shall occur a complete or partial withdrawal from, or default, within the meaning of Section 4219(c)(5) of ERISA, with respect to, one or more Multiemployer Plans which could reasonably be expected to cause one or more members of the ERISA Group to incur a current payment obligation in excess of $50,000,000; or

(xi) the Company shall fail within sixty (60) days to pay, bond or otherwise discharge any judgment or order for the payment of money in excess of $20,000,000, entered against the Company that is not stayed on appeal or otherwise being appropriately contested in good faith; or

(xii) a Change of Control shall have occurred;

For purposes of the foregoing:

"Change of Control" means (i) the acquisition by any person, or two or more persons acting in concert, of beneficial ownership (within the meaning of Rule 13d-3 of the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended) of 25% or more of the outstanding shares of voting stock of PPL Corporation or its successors or (ii) the failure at any time of PPL Corporation or its successors to own 80% or more of the outstanding shares of the voting stock in the Company.

"Material Debt" means debt (other than debt under the Loan Documents) of the Company in a principal or face amount exceeding $50,000,000

Appendix C of the Reoffering Circular is hereby amended to read in its entirety as follows:

Sumitomo Mitsui Banking Corporation, New York Branch

The information under this heading has been provided solely by Sumitomo Mitsui Banking Corporation, New York Branch and is believed to be reliable. This information has not been verified independently by the Company, the Issuer or the Remarketing Agent. The Company, the Issuer and the Remarketing Agent make no representation whatsoever as to the accuracy, adequacy or completeness of such information.

Sumitomo Mitsui Banking Corporation

Sumitomo Mitsui Banking Corporation (*Kabushiki Kaisha Mitsui Sumitomo Ginko*) ("SMBC") is a joint stock corporation with limited liability (*Kabushiki Kaisha*) under the laws of Japan. The registered head office of SMBC is located at 1-2, Yurakucho 1-chome, Chiyoda-ku, Tokyo, Japan.

SMBC was established in April 2001 through the merger of two leading banks, The Sakura Bank, Limited and The Sumitomo Bank, Limited. In December 2002, Sumitomo Mitsui Financial Group, Inc. ("SMFG") was established through a stock transfer as a holding company under which SMBC became a wholly owned subsidiary. SMFG reported ¥ 123,159,513 million in consolidated total assets as of March 31, 2010.

SMBC is one of the world's leading commercial banks and provides an extensive range of banking services to its customers in Japan and overseas. In Japan, SMBC accepts deposits, makes loans and extends guarantees to corporations, individuals, governments and governmental entities. It also offers financing solutions such as syndicated lending, structured finance and project finance. SMBC also underwrites and deals in bonds issued by or under the guarantee of the Japanese government and local government authorities, and acts in various administrative and advisory capacities for certain types of corporate and government bonds. Internationally, SMBC operates through a network of branches, representative offices, subsidiaries and affiliates to provide many financing products including syndicated lending and project finance.

The New York Branch of SMBC is licensed by the State of New York Banking Department to conduct branch banking business at 277 Park Avenue, New York, New York, and is subject to examination by the State of New York Banking Department and the Federal Reserve Bank of New York.

Financial and Other Information

Audited consolidated financial statements for SMFG and its consolidated subsidiaries for the fiscal years ended March 31, 2010, as well as certain unaudited financial information for SMFG and SMBC for the fiscal period ended through December 31, 2010, as well as other corporate data, financial information and analyses are available in English on the website of the Parent at www.smfg.co.jp/english.

The information herein has been obtained from SMBC, which is solely responsible for its content. The delivery of the Reoffering Circular shall not create any implication that there has been no change in the affairs of SMBC since the date hereof, or that the information contained or referred herein is correct as of any time subsequent to its date.

Appendix A of the Reoffering Circular is hereby amended to read in its entirety as follows:

Appendix A

Kentucky Utilities Company –

Financial Statements and Additional Information

This Appendix A includes a description of the Business of Kentucky Utilities Company ("KU"), certain risk factors associated with KU, Selected Financial Information, Management's Discussion and Analysis, and the Consolidated Financial Statements as of December 31, 2010 and 2009 and for the Years Ended December 31, 2010, 2009, and 2008 (Audited).

The information contained in this Appendix A relates to and has been obtained from KU and from other sources as shown herein. The delivery of this Supplement shall not create any implication that there has been no change in the affairs of KU since the date hereof, or that the information contained or incorporated by reference in this Appendix A is correct at any time subsequent to its date. In this Appendix A, "KU", "the Company", "we", "us" or "our" refer to Kentucky Utilities Company.

Summary

Kentucky Utilities Company

Kentucky Utilities Company, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 514,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and to less than 10 customers in Tennessee. Our service area covers approximately 6,600 noncontiguous square miles. Approximately 98% of the electricity generated by us is produced by our coal-fired electric generating stations. The remainder is generated by natural gas and oil fueled combustion turbines and a hydroelectric power plant. In Virginia, we operate under the name Old Dominion Power Company. We also sell wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of LG&E and KU Energy LLC. On November 1, 2010, PPL Corporation purchased all of the interests of LG&E and KU Energy LLC and, indirectly, all of the stock of the Company from E.ON AG, making KU an indirect wholly-owned subsidiary of PPL Corporation. KU's affiliate, Louisville Gas and Electric Company ("LG&E"), is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and natural gas in Kentucky.

Kentucky Utilities Company

Financial Statements and Additional Information

As of December 31, 2010 and 2009 and

for the years ended December 31, 2010, 2009 and 2008

Index of Abbreviations

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Company	Kentucky Utilities Company
CT	Combustion Turbine
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Electric Energy, Inc.
EKPC	East Kentucky Power Cooperative, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC and Subsidiaries
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
Fidelia	Fidelia Corporation (an E.ON affiliate)
GAAP	U.S. Generally Accepted Accounting Principles
GAC	Group Annuity Contract
GHG	Greenhouse Gas
Gwh	Gigawatt hours or one thousand Mwh
IBEW	International Brotherhood of Electrical Workers
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
IRS	Internal Revenue Service
KCCS	Kentucky Consortium for Carbon Storage
KDAQ	Kentucky Division for Air Quality
Kentucky Commission	Kentucky Public Service Commission
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
kWh	Kilowatt hours
LG&E	Louisville Gas and Electric Company
LIBOR	London Interbank Offered Rate
LKE	LG&E and KU Energy LLC and Subsidiaries (formerly E.ON U.S. LLC and Subsidiaries)
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units

Index of Abbreviations

Moody's	Moody's Investor Services, Inc.
MVA	Megavolt-ampere
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NO_2	Nitrogen Dioxide
NOV	Notice of Violation
NOx	Nitrogen Oxide
OATT	Open Access Transmission Tariff
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation
PPL	PPL Corporation
Predecessor	The Company during the time period prior to November 1, 2010
PUHCA 2005	Public Utility Holding Company Act of 2005
RSG	Revenue Sufficiency Guarantee
S&P	Standard & Poor's Rating Service
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
Servco	LG&E and KU Services Company (formerly E.ON U.S. Services Inc.)
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool, Inc
Successor	The Company during the time period after October 31, 2010
TC1	Trimble County Unit 1
TC2	Trimble County Unit 2
TVA	Tennessee Valley Authority
Utilities	KU and LG&E
VDT	Value Delivery Team Process
Virginia Commission	Virginia State Corporation Commission

Table of Contents

Forward-Looking Information

KU uses forward-looking statements in this annual report. Statements that are not historical facts are forward-looking statements, and are based on beliefs and assumptions of management, and on information currently available to management. Forward-looking statements include statements preceded by, followed by or using such words as “believe,” “expect,” “anticipate,” “plan,” “estimate” or similar expressions. Such statements speak only as of the date they are made, and the Company undertakes no obligation to update publicly any of them in light of new information or future events. Actual results may materially differ from those implied by forward-looking statements due to known and unknown risks and uncertainties. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- fuel supply availability;
- weather conditions affecting generation production, customer energy use and operating costs;
- operation, availability and operating costs of existing generation facilities;
- transmission and distribution system conditions and operating costs;
- collective labor bargaining negotiations;
- the outcome of litigation against the Company;
- potential effects of threatened or actual terrorism or war or other hostilities;
- commitments and liabilities;
- market demand and prices for energy, capacity, transmission services, emission allowances and delivered fuel;
- competition in retail and wholesale power markets;
- liquidity of wholesale power markets;
- defaults by counterparties under the Company’s energy, fuel or other power product contracts;
- market prices of commodity inputs for ongoing capital expenditures;
- capital market conditions, including the availability of capital or credit, changes in interest rates, and decisions regarding capital structure;
- the fair value of debt and equity securities and the impact on defined benefit costs and resultant cash funding requirements for defined benefit plans;
- interest rates and their effect on pension and retiree medical liabilities;
- volatility in or the impact of other changes in financial or commodity markets and economic conditions;
- profitability and liquidity, including access to capital markets and credit facilities;
- new accounting requirements or new interpretations or applications of existing requirements;
- securities and credit ratings;
- current and future environmental conditions and requirements and the related costs of compliance, including environmental capital expenditures, emission allowance costs and other expenses;
- political, regulatory or economic conditions in states, regions or countries where the Company conducts business;
- receipt of necessary governmental permits, approvals and rate relief;
- new state or federal legislation, including new tax, environmental, health care or pension-related legislation;
- state or federal regulatory developments;
- the impact of any state or federal investigations applicable to the Company and the energy industry;
- the effect of any business or industry restructuring;
- development of new projects, markets and technologies;

- performance of new ventures; and
- asset acquisitions and dispositions.

In light of these risks and uncertainties, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than the Company has described. For additional details regarding these and other risks and uncertainties, see Risk Factors.

Business

General

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 514,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in five counties in southwestern Virginia and less than ten customers in Tennessee. KU's service area covers approximately 6,600 noncontiguous square miles. Approximately 98% of the electricity generated by KU is produced by its coal-fired electric generating stations. The remainder is generated by natural gas and oil fueled CTs and a hydroelectric power plant. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

On November 1, 2010, KU became an indirect wholly owned subsidiary of PPL, when PPL acquired all of the outstanding limited liability company interests in the Company's direct parent, LKE, from E.ON US Investments Corp. LKE, a Kentucky limited liability company, also owns the affiliate, LG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy and distribution and sale of natural gas in Kentucky. Following the acquisition, the Company's business has not changed. KU and LG&E are continuing as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies.

Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K.

Predecessor and Successor

KU's historical financial results are presented using "Predecessor" or "Successor" to designate the periods before or after PPL's acquisition of LKE. Predecessor covers the time period prior to November 1, 2010. Successor covers the time period after October 31, 2010. Certain accounting and presentation methods were changed to acceptable alternatives to conform to PPL accounting policies and the cost basis of certain assets and liabilities were changed as of November 1, 2010, as a result of the application of push-down accounting. Consequently, the financial position, results of operations and cash flows for the Successor period are not comparable to the Predecessor period.

Despite the separate presentation, the core operations of the Company have not changed. See Note 1, Summary of Significant Accounting Policies, for the major differences in Predecessor and Successor accounting policies. See Note 2, Acquisition by PPL, for information regarding the acquisition and the purchase accounting adjustments.

Operations

Dollars are in millions unless otherwise noted.

The sources of operating revenues and volumes of sales for the following periods in 2010, 2009 and 2008 were as follows:

	Successor		Predecessor					
	November 1, 2010 through December 31, 2010		January 1, 2010 through October 31, 2010		Year Ended December 31, 2009		Year Ended December 31, 2008	
	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)
Residential	$ 106	1,394	$ 440	5,788	$ 480	6,594	$ 462	6,803
Industrial and commercial	117	1,876	588	9,152	637	10,171	636	10,709
Municipals	15	326	88	1,676	91	1,848	92	1,971
Other retail	20	273	114	1,453	118	1,647	108	1,707
Wholesale	5	68	18	376	29	660	107	2,894
	$ 263	3,937	$ 1,248	18,445	$ 1,355	20,920	$ 1,405	24,084

KU's peak load in 2010 was 4,517 Mw on December 15, 2010, when the temperature dropped to a low of 3 degrees Fahrenheit in Lexington. KU's all time peak load was 4,640 Mw and occurred on January 16, 2009, when the temperature dropped to a low of -2 degrees Fahrenheit in Lexington.

The Company's power generating system includes coal-fired steam generating stations, with natural gas and oil fueled CTs which supplement the system during peak or emergency periods. As of December 31, 2010, KU's system capacity was:

Fuel/Plant	Total Summer Mw Capacity (a)	% Ownership	Ownership or Lease Interest in Mw	Location
Coal (steam)				
Ghent	1,918	100.00	1,918	Carroll County, KY
E.W. Brown	684	100.00	684	Mercer County, KY
Green River	163	100.00	163	Muhlenberg County, KY
Tyrone	71	100.00	71	Woodford County, KY
OVEC - Clifty Creek (b)	1,304	2.50	33	Jefferson County, IN
OVEC - Kyger Creek (b)	1,086	2.50	27	Gallia County, OH
Total steam	5,226		2,896	
Natural gas/oil (combustion turbines)				
E.W. Brown Units 8-11	480	100.00	480	Mercer County, KY
Trimble County Units 7-10 (c)	640	63.00	403	Trimble County, KY
Trimble County Units 5-6 (c)	320	71.00	227	Trimble County, KY
E.W. Brown Units 6-7 (c)	338	62.00	214	Mercer County, KY
Paddy's Run (c)	158	47.00	74	Jefferson County, KY
E.W. Brown Unit 5	129	47.00	63	Mercer County, KY
Haefling	36	100.00	36	Fayette County, KY
Total combustion turbines	2,101		1,497	

Fuel/Plant	Total Summer Mw Capacity (a)	% Ownership	Ownership or Lease Interest in Mw	Location
Hydro				
Dix Dam Hydroelectric Station	24	100.00	24	Mercer County, KY
Total hydro	24		24	
Total system capacity	7,351		4,417	

(a) The capacity of generation units is based on a number of factors, including the operating experience and physical conditions of the units and may be revised periodically to reflect changed circumstances.
(b) KU is contractually entitled to 2.50% of OVEC's output based on a power purchase agreement which is comprised of annual minimum debt service payments, as well as contractually-required reimbursement of plant operating, maintenance and other expenses. OVEC's capacity is shown at unit nameplate ratings.
(c) Units are jointly owned with LG&E. See Note 14, Jointly Owned Electric Utility Plant, for further information.

With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. Unit 2 is coal-fired and has a capacity of 760 Mw, of which KU's share is 462 Mw.

On December 31, 2010, KU's transmission system included 132 substations (54 of which are shared with the distribution system) with transformer capacity of approximately 13,136 MVA and approximately 4,076 miles of lines. The distribution system included 480 substations (54 of which are shared with the transmission system) with transformer capacity of approximately 7,044 MVA, and approximately 14,123 miles of overhead lines and 2,221 miles of underground conduit.

KU had a power supply contract with OMU that was terminated by OMU in May 2010. KU owns 20% of EEI's common stock and 2.5% of OVEC's common stock. KU has power purchase rights for its portion of OVEC's output. Additional information regarding this relationship is provided in Note 1, Summary of Significant Accounting Policies and Note 13, Commitments and Contingencies.

KU contracts with the TVA to act as KU's transmission reliability coordinator and SPP to function as KU's independent transmission operator, pursuant to FERC requirements. The TVA and SPP contracts provide services through August 31, 2011 and August 31, 2012, respectively. See Note 3, Rates and Regulatory Matters, for further information.

KU and LG&E jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has

excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are recorded as intercompany wholesale sales and purchases and are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the Utilities. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

Substantially all of KU's real and tangible property located in Kentucky is subject to a mortgage lien, securing its first mortgage bonds. See Note 11, Long-Term Debt, for further information.

Rates and Regulations

PPL, KU's ultimate parent, is a holding company under PUHCA 2005. PPL, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries are subject to extensive regulation by the FERC with respect to numerous matters, including: electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. KU believes that it has adequate authority (including financing authority) under existing FERC Orders and regulations to conduct its business and will seek additional authorization when necessary.

The Company is subject to the jurisdiction of the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority in virtually all matters related to electric utility regulation, and as such, its accounting is subject to the regulated operations guidance of the FASB ASC. Given its competitive position in the marketplace and the status of regulation in Kentucky, Virginia and Tennessee there are no plans or intentions to discontinue the application of the regulated operations guidance of the FASB ASC.

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments Corp., PPL and E.ON.

The transaction was subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including the FERC and state regulators in Kentucky, Virginia and Tennessee) and the absence of injunctions or restraints imposed by governmental entities.

Change of control and financing-related applications were filed on May 28, 2010, with the Kentucky Commission and on June 15, 2010, with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings and data request filings and responses occurred. Early termination of the Hart-Scott-Rodino waiting period was received on August 2, 2010.

A hearing in the Kentucky Commission proceedings was held on September 8, 2010, at which time a unanimous settlement agreement was presented. In the settlement, KU committed that no base rate increases would take effect before January 1, 2013. The KU rate increases that took effect on August 1,

2010, were not impacted by the settlement. Under the terms of the settlement, KU retains the right to seek approval for the deferral of “extraordinary and uncontrollable costs.” Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and demand-side management cost trackers. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Company file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits KU to earn up to a 10.75% return on equity. Any earnings above a 10.75% return on equity will be shared with customers on a 50%/50% basis. On September 30, 2010, the Kentucky Commission issued an Order approving the transfer of ownership of KU via the acquisition of E.ON U.S. by PPL, incorporating the terms of the submitted settlement. On October 19, 2010 and October 21, 2010, respectively, Orders approving the acquisition of E.ON U.S. by PPL were received from the Virginia Commission and the Tennessee Regulatory Authority. The Commissions’ Orders contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In mid-September 2010, KU and other applicants in the FERC change of control proceeding reached an agreement with the protesters, whereby such protests have been withdrawn. The agreement, which was filed for consideration with the FERC, includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an agreement not to terminate certain KU municipal customer contracts prior to January 2017, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that KU agreed not to seek the same transaction-related cost from retail customers and agreements to coordinate with protesters in certain open or ongoing matters. A FERC Order approving the transaction was received on October 26, 2010, and the transaction was completed on November 1, 2010.

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $135 million annually. In June 2010, KU and all of the intervenors, except the AG, agreed to a stipulation providing for an increase in electric base rates of $98 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulation, including a return on equity range of 9.75-10.75%. The new rates became effective on August 1, 2010.

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based on a return on equity of 12%. As permitted, pursuant to a Virginia Commission Order, KU elected to implement the proposed rates effective November 1, 2009, on an interim basis. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing a base rate revenue increase of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU refunded approximately $1 million in interim rate amounts in excess of the ultimate approved rates.

In January 2009, a significant ice storm passed through KU’s service area causing approximately 199,000 customer outages, followed closely by a severe wind storm in February 2009 causing approximately 44,000 customer outages. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future

recovery approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $62 million based on its actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, the Company established a regulatory asset of $57 million for actual costs incurred. KU received approval in its 2010 base rate case to recover this asset over a ten year period with recovery beginning August 1, 2010.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service area causing significant outages and system damage. In October 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset and defer for future recovery approximately $3 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $3 million based on its actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, the Company established a regulatory asset of $2 million for actual costs incurred. The Company received approval in its 2010 base rate case to recover this asset over a ten year period beginning August 1, 2010.

In September 2008, KU filed an application with the FERC for increases in electric base rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from an all-in stated unit charge rates to an unbundled formula rate, including an annual adjustment mechanism. In May 2009, the FERC issued an Order approving a settlement among the parties in the case, incorporating increases of approximately 3% from prior rates and a return on equity of 11%. In May 2010, KU submitted to the FERC the proposed current annual adjustments to the formula rates, which incorporated certain proposed increases. Updated rates, including certain further adjustments from a review process involving wholesale requirements customers, became effective as of July 1, 2010.

By mutual agreement, the parties' settlement of the 2008 application left outstanding the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. An Order was issued by the FERC in July 2010, indicating that KU is not required to allocate a portion of any renewable resources to the twelve municipalities, thus resolving the remaining issue.

In July 2008, KU filed an application with the Kentucky Commission requesting an increase in electric base rates. In January 2009, KU, the AG, the KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which KU's electric base rates decreased by $9 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009.

For a further discussion of regulatory matters, see Note 3, Rates and Regulatory Matters.

<u>Coal Supply</u>

Coal-fired generating units provided approximately 98% of KU's net kWh generation for 2010. The remaining net generation was provided by natural gas and oil fueled CTs and a hydroelectric plant. Coal is expected to be the predominant fuel used by KU in the foreseeable future, with natural gas and oil

being used for peaking capacity and flame stabilization in coal-fired boilers or in emergencies. The Company has no nuclear generating units and has no plans to build any in the foreseeable future.

Fuel inventory is maintained at levels estimated to be necessary to avoid operational disruptions at the coal-fired generating units. Reliability of coal deliveries can be affected periodically by a number of factors including fluctuations in demand, coal mine production issues and other supplier or transporter operating difficulties.

KU has entered into coal supply agreements with various suppliers for coal deliveries for 2011 and beyond and normally augments its coal supply agreements with spot market purchases. The Company has a coal inventory policy which it believes provides adequate protection under most contingencies.

KU expects to continue purchasing most of its coal, which has sulfur content in the 0.7% - 3.5% range, from western and eastern Kentucky, West Virginia, southern Indiana, southern Illinois, Ohio and Wyoming for the foreseeable future. This supply, in combination with the installation of FGDs (SO_2 removal systems), KU expects its use of higher sulfur coal to increase, the combination of which is expected to enable KU to continue to provide electric service in compliance with existing environmental laws and regulations. Coal is delivered to KU's generating stations by a mix of transportation modes, including barge, truck and rail.

Seasonality

Demand for and market prices for electricity are affected by weather. As a result, KU's overall operating results in the future may fluctuate substantially on a seasonal basis, especially when more severe weather conditions such as heat waves or winter storms make such fluctuations more pronounced. The pattern of this fluctuation may change depending on the type and location of the facilities KU owns and the terms of its contracts to purchase or sell electricity.

Environmental Matters

General

Protection of the environment is a major priority for KU and a significant element of its business activities. KU's properties and operations are subject to extensive environmental-related oversight by federal, state and local regulatory agencies, including via air quality, water quality, waste management and similar laws and regulations. Therefore, KU must conduct its operations in accordance with numerous permit and other requirements issued under or contained in such laws or regulations.

Climate Change

Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3% by 2012, 17% by 2020 and 83% by 2050. Similar legislation has been considered in the U.S. Senate, but the prospects for

passage remain uncertain. In late 2009, the EPA issued a final endangerment finding relating to mobile sources of GHGs and a GHG reporting requirement beginning in 2010. In 2010, the EPA issued a final rule requiring implementation of best available control technology for GHG emissions from new or modified power plants, effective January 2011. In December 2010, the EPA announced that it intends to propose New Source Performance Standards addressing GHG emissions from new and existing power plants, with a proposed rule expected in July 2011. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, KU, as a primarily coal-fired utility, could be highly affected by such proceedings.

Among other emissions, GHGs include carbon-dioxide, which is produced via the combustion of fossil fuels such as coal and natural gas. KU's generating fleet is approximately 66% coal-fired, 34% oil/natural gas-fired and less than 1% hydroelectric based on capacity. During 2010, KU produced approximately 98% of its electricity from coal, 2% from natural gas combustion and less than 1% from hydroelectric generation, based on Mwh. During 2010, KU's emissions of GHGs were approximately 16.4 million metric tons of carbon-dioxide equivalents from KU's owned or controlled generation sources. While its generation activities account for the bulk of its GHG emissions, other GHG sources at KU include operation of motor vehicles and powered equipment, leakage or evaporation associated with natural gas pipelines, refrigerating equipment and similar activities.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. Based on prior regulatory precedent, KU currently anticipates that many of such direct costs may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, but the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change and other environmental matters will likely increase the level of capital expenditures and operating and maintenance costs incurred by the Company during the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. In order to comply with the coal combustion residual rules and the above referenced air rules, capital expenditures for KU are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary. This estimate does not include compliance with GHG rules or contemplated water-related environmental changes. See Risk Factors, Management's Discussion and Analysis and Note 13, Commitments and Contingencies, for further information.

State Executive or Legislative Matters

In November 2008, the Commonwealth of Kentucky issued an action plan to create efficient, sustainable energy solutions and strategies and move toward state energy independence. The plan outlines the following seven strategies to work toward these goals:

- Improve the energy efficiency of Kentucky's homes, buildings, industries and transportation fleet
- Increase Kentucky's use of renewable energy
- Sustainably grow Kentucky's production of biofuels
- Develop a coal-to-liquids industry in Kentucky to replace petroleum-based liquids
- Implement a major and comprehensive effort to increase natural gas supplies, including coal-to-natural gas in Kentucky
- Initiate aggressive carbon capture/sequestration projects for coal-generated electricity in Kentucky
- Examine the use of nuclear power for electricity generation in Kentucky

In December 2009, the Governor of Kentucky's Executive Task Force on Biomass and Biofuels issued a final report to establish potential strategic actions to develop biomass and biofuels industries in Kentucky. The plan noted the potential importance of biomass as a renewable energy source available to Kentucky and discussed various goals or mechanisms, such as the use of approximately 25 million tons of biomass for generation fuel annually, allotment of electricity and natural gas taxes and state tax credits to support biomass development.

In January 2010, a state-established Kentucky Climate Action Plan Council (the "Council") commenced formal activities. The Council, which includes governmental, industry, consumer and other representatives, seeks to identify possible Kentucky responses to potential climate change and federal legislation, including increasing statewide energy efficiency, energy independence and economic growth. The Council has established various technical work groups, including in the areas of energy supply and energy efficiency/conservation, to provide input, data and recommendations.

During the current session of the Kentucky General Assembly, as during prior legislative sessions, legislators have introduced or are expected to introduce various bills with respect to environmental or utility matters, including potential requirements relating to renewable energy portfolios, energy conservation measures, coal mining or coal byproduct operations and other matters. The current session is scheduled to end in March 2011 and until such time the prospects and final terms of any such legislation cannot be determined. Legislative and regulatory actions as a result of these proposals and their impact on KU, which may be significant, cannot currently be predicted.

Franchises and Licenses

KU provides electric delivery service in its various service areas pursuant to certain franchises, licenses, statutory service areas, easements and other rights or permissions granted by state legislatures, cities or municipalities or other entities.

Competition

There are currently no other electric utilities operating within the electric service areas of KU. Neither the Kentucky General Assembly nor the Kentucky Commission has adopted or approved a plan or timetable for retail electric industry competition in Kentucky. The nature or timing of any legislative or regulatory actions regarding industry restructuring and their impact on KU, which may be significant, cannot currently be predicted. Virginia, formerly a competitive jurisdiction, has enacted legislation which implements a hybrid model of cost-based regulation. See Note 3, Rates and Regulatory Matters, for further information.

Employees and Labor Relations

KU had 974 employees at December 31, 2010, consisting of 973 full-time employees and 1 part-time employee. Of the total employees, 145, or 15%, were operating, maintenance and construction employees represented by the IBEW Local 2100 and the United Steelworkers of America ("USWA") Local 9447-01. In August 2009, the Company and its employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement that provides for negotiated increases or changes to wages, benefits or other provisions and annual wage re-openers. In August 2008, the Company and its employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement that provides for negotiated increases or changes to wages, benefits or other provisions and annual wage re-openers.

Officers of the Company

Officers are elected annually by the Board of Directors. There are no family relationships among any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

Except as may be set forth in Legal Proceedings, there have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

Listed below are the executive officers at December 31, 2010.

Name	Age	Positions Held During the Past Five Years	Dates
Victor A. Staffieri	55	Chairman of the Board, President and Chief Executive Officer	May 2001 – present
John R. McCall	67	Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer	July 1994 – present
Chris Hermann	63	Senior Vice President – Energy Delivery	February 2003 – present
Paula H. Pottinger	53	Senior Vice President – Human Resources	January 2006 – present
S. Bradford Rives	52	Chief Financial Officer	September 2003 – present
Paul W. Thompson	53	Senior Vice President – Energy Services	June 2000 – present

Officers generally serve in the same capacities at the Company, LKE and LG&E.

Risk Factors

Any of the events or circumstances described as risks below could result in a significant or material adverse effect on the business, results of operations, cash flows or financial condition. The risks and uncertainties described below may not be the only risks and uncertainties that KU faces. Additional risks and uncertainties not currently known or that KU currently deems immaterial may also result in a significant or material adverse effect on the business, results of operations, cash flow or financial condition.

KU's business is subject to significant and complex governmental regulation.

Various federal and state entities, including but not limited to the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority, regulate many aspects of utility operations of KU, including the following:

- the rates that KU may charge and the terms and conditions of the Company's service and operations;
- financial and capital structure matters;
- siting and construction of facilities;
- mandatory reliability and safety standards and other standards of conduct;
- accounting, depreciation and cost allocation methodologies;
- tax matters;
- affiliate restrictions;
- acquisition and disposal of utility assets and securities; and
- various other matters.

Such regulations or changes thereto may subject KU to higher operating costs or increased capital expenditures and failure to comply could result in sanctions or possible penalties. In any rate-setting proceedings, federal or state agencies, intervenors and other permitted parties may challenge rate requests and ultimately reduce, alter or limit the rates the Company seeks.

The profitability of KU is highly dependent on its ability to recover the costs of providing energy and utility services to its customers and earn an adequate return on its capital investments. KU currently provides services to retail customers at rates approved by one or more federal or state regulatory commissions, including those commissions referred to above. While these rates are generally regulated based on an analysis of their costs incurred in a base year, the rates KU is allowed to charge may or may not match its costs at any given time. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commissions will consider all of the costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of KU's costs or an adequate return on KU's capital investments. If the Company's costs are not adequately recovered through rates, it could have an adverse affect on the business, results of operations, cash flows or financial condition.

As part of the PPL acquisition commitments, KU has agreed, subject to certain limited exceptions such as fuel and environmental cost recoveries, that no base rate increase would take effect for Kentucky retail customers before January 1, 2013.

Transmission and interstate market activities of KU, as well as other aspects of the business, are subject to significant FERC regulation.

KU is subject to extensive regulation by the FERC covering matters including rates charged to transmission users, market-based or cost-based rates applicable to wholesale customers; interstate power market structure; construction and operation of transmission facilities; mandatory reliability standards; standards of conduct and affiliate restrictions and other matters. Existing FERC regulation, changes thereto or issuances of new rules or situations of non-compliance, including but not limited to the areas of market-based tariff authority, RSG resettlements in the MISO market, mandatory reliability standards and natural gas transportation regulation can affect the earnings, operations or other activities of KU.

Changes in transmission and wholesale power market structures could increase costs or reduce revenues.

Wholesale sales fluctuate with regional demand, fuel prices and contracted capacity. Changes to transmission and wholesale power market structures and prices may occur in the future, are not estimable and may result in unforeseen effects on energy purchases and sales, transmission and related costs or revenues. These can include commercial or regulatory changes affecting power pools, exchanges or markets in which KU participates.

KU undertakes significant capital projects and these activities are subject to unforeseen costs, delays or failures, as well as risk of inadequate recovery of resulting costs.

KU's business is capital intensive and requires significant investments in energy generation and distribution and other infrastructure projects, such as projects for environmental compliance. The completion of these projects without delays or cost overruns is subject to risks in many areas, including the following:

- approval, licensing and permitting;
- land acquisition and the availability of suitable land;
- skilled labor or equipment shortages;
- construction problems or delays, including disputes with third party intervenors; increases in commodity prices or labor rates;
- contractor performance;
- environmental considerations and regulations;
- weather and geological issues; and
- political, labor and regulatory developments.

Failure to complete capital projects on schedule or on budget, or at all, could adversely affect the Company's financial performance, operations and future growth.

The costs of compliance with, and liabilities under, environmental laws are significant and are subject to continual changes.

Extensive federal, state and local environmental laws and regulations are applicable to KU's air emissions, water discharges and the management of hazardous and solid waste, among other areas; and

the costs of compliance or alleged non-compliance cannot be predicted with certainty but could be material. In addition, KU's costs may increase significantly if the requirements or scope of environmental laws or regulations, or similar rules, are expanded or changed from prior versions by the relevant agencies. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions. Many of these environmental law considerations are also applicable to the operations of key suppliers, or customers, such as coal producers, industrial power users, etc., and may impact the costs of their products or their demand for KU's services.

KU is subject to operational and financial risks regarding certain on-going developments concerning environmental regulation.

A number of regulatory initiatives have been implemented or are under development which could have the effect of significantly increasing the environmental regulation or operational or compliance costs related to a number of emissions or operating activities which are associated with the combustion of coal as occurs at the Company's generating stations. Such developments could include potential new or revised federal or state legislation or regulation regarding emissions of NOx, SO_2, mercury and other particulates generally and regarding storage of coal combustion byproducts. Additional regulatory initiatives may occur in other areas involving the Company's operations, including revision of limitations on water discharge or intake activities or increased standards relating to polychlorinated biphenyl usage. Compliance with any new laws or regulations in these matters could result in significant changes to KU's operations, significant capital expenditures by the Company or significant increases in the cost of conducting business.

Operating results are affected by weather conditions, including storms and seasonal temperature variations, as well as by significant man-made or accidental disturbances, including terrorism or natural disasters.

These weather or other factors can significantly affect the finances or operations of KU by changing demand levels; causing outages; damaging infrastructure or requiring significant repair costs; affecting capital markets and general economic conditions or impacting future growth.

KU is subject to operational and financial risks regarding potential developments concerning global climate change.

Various regulatory and industry initiatives have been implemented or are under development to regulate or otherwise reduce emissions of GHGs, which are emitted from the combustion of fossil fuels such as coal and natural gas, as occurs at the Company's generating stations. Such developments could include potential federal or state legislation or industry initiatives allocating or limiting GHG emissions; establishing costs or charges on GHG emissions or on fuels relating to such emissions; requiring GHG capture and sequestration; establishing renewable portfolio standards or generation fleet-diversification requirements to address GHG emissions; promoting energy efficiency and conservation; changes in transmission grid construction, operation or pricing to accommodate GHG-related initiatives; or other measures. The generation fleet of KU is predominantly coal-fired and may be highly impacted by developments in this area. Compliance with any new laws or regulations regarding the reduction of GHG emissions could result in significant changes to KU's operations, significant capital expenditures by the Company and a significant increase in the cost of conducting business. KU may face strong

competition for, or difficulty in obtaining, required GHG-compliance related goods and services, including construction services, emissions allowances and financing, insurance and other inputs relating thereto. Increases in KU's costs or prices of producing or selling electric power due to GHG-related developments could materially reduce or otherwise affect the demand, revenue or margin levels applicable to its power, thus adversely affecting its financial condition or results of operations.

KU is subject to physical, market and economic risks relating to potential effects of climate change.

Climate change may produce changes in weather or other environmental conditions, including temperature or precipitation changes, such as warming or drought. These changes may affect farm and agriculturally-dependent businesses and activities, which are an important part of Kentucky's economy, and thus may impact consumer demand for electric power. Temperature increases could result in increased overall electricity volumes or peaks and precipitation changes could result in altered availability of water for plant cooling operations. These or other meteorological changes could lead to increased operating costs, capital expenses or power purchase costs by KU. Conversely, climate change could have a number of potential impacts tending to reduce demand. Changes may entail more frequent or more intense storm activity, which, if severe, could temporarily disrupt regional economic conditions and adversely affect electricity demand levels. As discussed in other risk factors, storm outages and damage often directly decrease revenues or increase expenses, due to reduced usage and higher restoration charges, respectively. GHG regulation could increase the cost of electric power, particularly power generated by fossil fuels, and such increases could have a depressive effect on the regional economy. Reduced economic and consumer activity in the service area of KU, both in general and specific to certain industries and consumers accustomed to previously low-cost power, could reduce demand for KU's electricity. Also, demand for services could be similarly lowered should consumers' preferences or market factors move toward favoring energy efficiency, low-carbon power sources or reduced electric usage generally.

The business of KU is subject to risks associated with local, national and worldwide economic conditions.

The consequences of prolonged recessionary conditions may include a lower level of economic activity and uncertainty or volatility regarding energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption, unfavorable changes in energy and commodity prices and slower customer growth, which may adversely affect KU's future revenues and growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and the ability to raise capital. A deterioration of economic conditions may lead to decreased production by KU's industrial customers and, therefore, lower consumption of electricity. Decreased economic activity may also lead to fewer commercial and industrial customers and increased unemployment, which may in turn impact residential customers' ability to pay. Further, worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure. Changes in global demand may impact the ability to acquire sufficient supplies and the cost of those commodities may be higher than expected.

KU's business is concentrated in the Midwest United States, specifically Kentucky and Virginia.

Although the business of KU is concentrated in Kentucky and Virginia, it also operates in Tennessee. Local and regional economic conditions, such as population growth, industrial growth, expansion and economic development or employment levels, as well as the operational or financial performance of major industries or customers, can affect the demand for energy and KU's results of operations. Significant industries and activities in the service area of KU include aluminum and steel smelting and fabrication; chemical processing; coal, mineral and ceramic related activities; educational institutions; health care facilities; paper and pulp processing; metal fabrication; and water and sewer utilities. Any significant downturn in these industries or activities or in local and regional economic conditions in KU's service area may adversely affect the demand for electricity in the service area.

KU is subject to operational risks relating to KU's generating plants, transmission facilities, distribution equipment, information technology systems and other assets and activities.

Operation of power plants, transmission and distribution facilities, information technology systems and other assets and activities subjects KU to many risks, including the breakdown or failure of equipment; accidents; security breaches, viruses or outages affecting information technology systems; labor disputes; obsolescence; delivery/transportation problems and disruptions of fuel supply and performance below expected levels. Occurrences of these events may impact the ability of KU to conduct its business efficiently or lead to increased costs, expenses or losses.

Although KU maintains customary insurance coverage for certain of these risks common to utilities, it does not have insurance covering the transmission and distribution systems, other than substations, because it has found the cost of such insurance to be prohibitive. If KU is unable to recover the costs incurred in restoring transmission and distribution properties following damage resulting from ice storms, tornados or other natural disasters or to recover the costs of other liabilities arising from the risks of its business, through a change in rates or otherwise, or if such recovery is not received on a timely basis, it may not be able to restore losses or damages to its properties without an adverse effect on its financial condition, results of operations or its reputation.

KU is subject to liability risks relating to its generation, transmission, distribution and retail businesses.

The conduct of the physical and commercial operations of KU subjects it to many risks, including risks of potential physical injury, property damage or other financial affects, caused to or caused by employees, customers, contractors, vendors, contractual or financial counterparties and other third parties.

KU could be negatively affected by rising interest rates, downgrades to bond credit ratings or other negative developments in its ability to access capital markets.

In the ordinary course of business, KU is reliant upon adequate long-term and short-term financing means to fund significant capital expenditures, debt interest or maturities and operating needs. As a capital-intensive business, the Company is sensitive to developments in interest rate levels; credit rating considerations; insurance, security or collateral requirements; market liquidity and credit availability and

refinancing steps necessary or advisable to respond to credit market changes. Changes in these conditions could result in increased costs and decreased liquidity available to the Company.

KU is subject to commodity price risk, credit risk, counterparty risk and other risks associated with the energy business.

General market or pricing developments or failures by counterparties to perform their obligations relating to energy, fuels, other commodities, goods, services or payments could result in potential increased costs to the Company.

KU is subject to risks associated with defined benefit retirement plans, health care plans, wages and other employee-related matters.

KU sponsors pension and postretirement benefit plans for its employees. Risks with respect to these plans include adverse developments in legislation or regulation, future costs or funding levels, returns on investments, market fluctuations, interest rates and actuarial matters. Changes in health care rules, market practices or cost structures can affect current or future funding requirements or liabilities. Without sustained growth in respective investments over time to increase the value of plan assets, KU could be required to fund plans with significant amounts of cash. KU is also subject to risks related to changing wage levels, whether related to collective bargaining agreements or employment market conditions, ability to attract and retain key personnel and changing costs of providing health care benefits.

KU is subject to risks associated with federal and state tax regulations.

Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact results of operations. KU is required to make judgments in order to estimate its obligations to taxing authorities. These tax obligations include income, property, sales and use and employment-related taxes. KU also estimates its ability to utilize tax benefits and tax credits. Due to the revenue needs of the states and jurisdictions in which KU operates, various tax and fee increases may be proposed or considered. KU cannot predict whether legislation or regulation will be introduced or the effect on the Company of any such changes. If enacted, any changes could increase tax expense and could have a negative impact on its results of operations and cash flows.

Legal Proceedings

Rates and Regulatory Matters

For a discussion of current rates and regulatory matters, including recent electric base rate increase proceedings, rate commitments in change-of-control proceedings, TC2 proceedings, FERC, Kentucky Commission and Virginia Commission proceedings and other rates or regulatory matters affecting KU, see Note 3, Rates and Regulatory Matters, and Note 13, Commitments and Contingencies.

Environmental

For a discussion of environmental matters, including potential coal combustion byproduct or ash pond regulation; additional reductions in SO_2, NOx and other regulated emissions; NOVs and other emissions proceedings; environmental permit challenges; and other environmental items affecting KU, see Risk Factors, Note 3, Rates and Regulatory Matters, and Note 13, Commitments and Contingencies.

Climate Change

For a discussion of matters relating to potential climate change, GHG emission or global warming developments, including increased legislative and regulatory activity which could limit or increase costs applicable to fossil fuel generation sources, legal proceedings claiming damages relating to global warming, GHG reporting requirements and other matters, see Business, Risk Factors, Management's Discussion and Analysis and Note 13, Commitments and Contingencies.

Litigation

In connection with an administrative proceeding alleging a violation by a former Argentine affiliate under that country's 2002-2003 emergency currency exchange laws, claims are pending against the affiliate's then directors, including two individuals who are executive officers of the Company, in a specialized Argentine financial criminal court. Under applicable Argentine laws, directors of a local company may be liable for monetary penalties for a subject company's violations of the currency laws. The affiliate and the relevant executive officers believe their actions were in compliance with the relevant laws and have presented defenses in the administrative and criminal proceedings. LKE has standard indemnification arrangements with its executive officers. The former affiliate is now owned by a third party, which has agreed to indemnify LKE and the relevant executive officers.

For a discussion of litigation matters, see Note 13, Commitments and Contingencies.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against KU. To the extent that damages are assessed in any of these lawsuits, the Company believes that its insurance coverage is adequate. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits and claims will have a material adverse effect on KU's financial position or results of operations.

Selected Financial Data

Dollars are in millions unless otherwise noted.

	Successor	Predecessor				
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,			
			2009	2008	2007	2006
Operating revenues	$ 263	$ 1,248	$ 1,355	$ 1,405	$ 1,272	$ 1,210
Operating income	$ 65	$ 285	$ 269	$ 260	$ 267	$ 235
Net income	$ 35	$ 140	$ 133	$ 158	$ 167	$ 152
Total assets	$ 6,059	$ 5,145	$ 4,956	$ 4,518	$ 3,796	$ 3,148
Long-term debt obligations (including amounts due within one year)	$ 1,841	$ 1,682	$ 1,682	$ 1,532	$ 1,264	$ 843

Management's Discussion and Analysis and Notes to Financial Statements should be read in conjunction with the above information.

Management’s Discussion and Analysis

Management’s Discussion and Analysis should be read in conjunction with the Financial Statements and Notes for the years ended December 31, 2010, 2009 and 2008. Dollars are in millions unless otherwise noted.

The purpose of “Management’s Discussion and Analysis” is to provide information about KU’s performance in implementing its’ strategies and managing risks and challenges. Specifically:

- “Overview” provides background regarding KU’s business and identifies significant matters with which management is primarily concerned in evaluation of KU’s financial condition and operating results.
- “Results of Operations” provides a description of KU’s operating results in 2010, 2009 and 2008, including a review of earnings and a brief outlook for 2011.
- “Financial Condition” provides an analysis of KU’s liquidity position and credit profile, including its sources of cash (including bank credit facilities and sources of operating cash flow) and uses of cash (including contractual obligations and capital expenditure requirements) and the key risks and uncertainties that impact KU’s past and future liquidity position and financial condition. This subsection also includes a discussion of KU’s current credit ratings.
- “Application of Critical Accounting Policies and Estimates” provides an overview of the accounting policies that are particularly important to the results of operations and financial condition of KU and that require its management to make significant estimates, assumptions and other judgments.

Overview

KU is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. See the Business section for a description of the business. The rates KU charges its customers requires approval of the appropriate regulatory government agency. See Note 3, Rates and Regulatory Matters, for information regarding rate cases, regulatory assets and liabilities and other regulatory matters.

KU and its affiliate, LG&E, are wholly owned subsidiaries of LKE, a Kentucky limited liability company. PPL acquired LKE on November 1, 2010. Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K. Following the acquisition, both KU and LG&E continue operating as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies. See Note 2, Acquisition by PPL, for further information regarding the acquisition.

In operating its business, the Company faces several risks including credit risks, liquidity risks, interest rate risks and commodity and price risks. For instance, the Company has credit risks from counterparties, customers and effects of its’ own credit ratings. KU attempts to manage these risks through the adoption of financial and operational risk management programs that, among other things, are designed to monitor and reduce its’ exposure to these risks. Identified within “Management’s

Discussion and Analysis" of "Financial Condition" and "Results of Operations" are risks KU's management currently consider material; these risks are not the only risks faced by KU. Additional risks not presently known or currently deemed immaterial may also impair KU's business operations. See Risk Factors and Financial Condition - Risk Management for further discussion.

Predecessor and Successor Financial Presentation

KU's financial statements and related financial and operating data include the periods before or after PPL's acquisition of LKE on November 1, 2010, and are labeled as Predecessor or Successor. KU applied push-down accounting to account for the acquisition. For accounting purposes only, push-down accounting is considered to create a new entity due to new cost basis assigned to assets, liabilities and equity as of the acquisition date. Consequently, KU's results of operations and cash flows for the Predecessor and Successor periods in 2010 are shown separately, rather than combined, in its audited financial statements.

In the "Management's Discussion and Analysis" of "Results of Operations" and "Financial Condition", the Company has included disclosure of the combined Predecessor and Successor results of operations and cash flows. Such presentation is considered to be a non-GAAP disclosure. KU has included such disclosure because the Company believes it facilitates the comparison of 2010 operating and financial performance to 2009 and 2008, and because the core operations of the Company have not changed as a result of the acquisition.

Competition

See the Business section for information concerning competition.

Environmental Matters

General

Protection of the environment is a major priority for KU and a significant element of its business activities. Extensive federal, state and local environmental laws and regulations are applicable to KU's air emissions, water discharges and the management of hazardous and solid waste, among other areas; and the costs of compliance or alleged non-compliance cannot be predicted with certainty but could be material. In addition, costs may increase significantly if the requirements or scope of environmental laws or regulations, or similar rules, are expanded or changed from prior versions by the relevant agencies. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions. Many of these environmental law considerations are also applicable to the operations of key suppliers, or customers, such as coal producers, industrial power users, etc., and may impact the costs of their products or their demand for KU's services.

Climate Change

Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of

Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3% by 2012, 17% by 2020 and 83% by 2050. Similar legislation has been considered in the U.S. Senate, but the prospects for passage remain uncertain. In late 2009, the EPA issued a final endangerment finding relating to mobile sources of GHGs and a GHG reporting requirement beginning in 2010. In 2010, the EPA issued a final rule requiring implementation of best available control technology for GHG emissions from new or modified power plants, effective January 2011. In December 2010, the EPA announced that it intends to propose New Source Performance Standards addressing GHG emissions from new and existing power plants, with a proposed rule expected in July 2011. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, KU, primarily a coal-fired utility, could be highly affected by such proceedings.

Other Environmental Regulatory Initiatives

The EPA has proposed or announced that it intends to propose a number of additional environmental regulations that could substantially impact utilities with coal-fired generating assets. These regulatory initiatives include revisions to the ambient air quality standards for SO_2, NO_2, ozone and particulate matter 2.5 microns in size or less, rules aimed at mitigating the interstate transport of SO_2 and NOx, a program governing emissions of hazardous air pollutants from utility generating units, a program for the management of coal combustion residuals, revised effluent guidelines for utility generating facilities and standards for cooling water intake structures. Such requirements could potentially mandate upgrade of existing emission controls, installation of additional emission controls such as FGDs, SCRs, fabric filter bag houses, activated carbon injection, wet electrostatic precipitators, closure of ash ponds and retrofit of landfills, installation of cooling towers, deployment of new water treatment technologies and retirement of facilities that cannot be retrofitted on a cost effective basis.

The cost to KU and the effect on KU's business of complying with potential GHG restrictions and other environmental regulatory initiatives will depend upon provisions of any final rules and how the rules are implemented by the EPA. Some of the design elements which may have the greatest effect on KU include (a) the required levels and timing of emissions caps, discharge limits or similar standards, (b) the sources covered by such requirements, (c) transition and mitigation provisions, such as phase-in periods, free allowances or price caps, (d) the availability and pricing of relevant mitigation or control technologies, goods or services and (e) economic, market and customer reaction to electricity price and demand changes due to environmental concerns.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. Based on prior regulatory precedent, KU currently anticipates that many of such direct costs may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, but the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change and other environmental matters will likely increase the level of

capital expenditures and operating and maintenance costs incurred by the Company during the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. In order to comply with the coal combustion residual rules and the above referenced air rules, capital expenditures for KU are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary. This estimate does not include compliance with GHG rules or contemplated water-related environmental changes. See Risk Factors and Note 13, Commitments and Contingencies, for further information.

Results of Operations

The utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year. Revenue and earnings are generally highest during the first and third quarters, and lowest in the second quarter, due to weather.

Net Income

The following table summarizes the significant components of net income for 2010, 2009 and 2008 and the changes therein:

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Total operating revenues	$ 1,511	$ 263	$ 1,248	$1,355	$ 1,405
Total operating expenses	1,161	198	963	1,086	1,145
Operating income	350	65	285	269	260
Equity in earnings of unconsolidated venture	3	-	3	1	30
Interest expense	14	8	6	6	14
Interest expense to affiliated companies	64	2	62	69	58
Other income (expense) – net	(2)	-	(2)	5	8
Income before income taxes	273	55	218	200	226
Income tax expense	98	20	78	67	68
Net income	$ 175	$ 35	$ 140	$ 133	$ 158

The change in KU's net income was as follows:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Total operating revenues	$ 156	$ (50)
Total operating expenses	75	(59)
Operating income	81	9
Equity in earnings of unconsolidated venture	2	(29)
Interest expense	8	(8)
Interest expense to affiliated companies	(5)	11
Other income (expense) – net	(7)	(3)
Income (loss) before income taxes	73	(26)
Income taxes	31	(1)
Net income	$ 42	$ (25)

Operating Revenues

The $156 million increase from 2009 to 2010 and $50 million decrease from 2008 to 2009 in operating revenues were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Retail sales volumes (a)	$ 73	$ (43)
Base rate price variance (b)	39	(5)
Demand revenue (c)	16	(1)
Sales to municipal customers (d)	12	(1)
Increased recoverable capital spending billed through the ECR	8	50
Other operating revenue primarily due to late payment charges	6	6
FAC price variance (e)	5	(2)
Merger surcredit termination in February 2009	2	13
Transmission sales	1	-
Increased recoverable program spending billed through the DSM	1	9
Wholesale sales (f)	(7)	(77)
VDT surcredit termination in August 2008	-	1
	$ 156	$ (50)

(a) Retail sales volumes increased during 2010 compared to 2009 as a result of increased consumption primarily due to increased heating degree days during the first and fourth quarters of 2010 and increased cooling degree days during the second and third quarters of 2010. Additionally, improved economic conditions in 2010 and significant storm outages in 2009 contributed to the increased volumes.

The decrease in retail sales volumes during 2009 compared to 2008 was attributable to reduced consumption by retail customers, as a result of milder weather and weakened economic conditions, in addition to significant storm outages during 2009.

(b) The increase in revenues due to the base rate price variance during 2010 compared to 2009 resulted from higher base rates effective August 1, 2010. See Note 3, Rates and Regulatory Matters, for further discussion of the 2010 Kentucky rate case.

The decrease in revenues due to the base rate price variance during 2009 compared to 2008 resulted from a reduction in base energy rates effective February 6, 2009. See Note 3, Rates and Regulatory Matters, for further discussion of the 2008 Kentucky rate case.

(c) Demand revenues increased during 2010 compared to 2009 as a result of higher demand rates effective August 1, 2010 and higher customer peak demand. See Note 3, Rates and Regulatory Matters, for further discussion of the 2010 Kentucky rate case.

(d) The increase in sales to municipal customers during 2010 compared to 2009 was primarily due to increased volumes as a result of increased cooling and heating degree days, improved economic conditions and a decline in storm outages.

(e) FAC revenues increased during 2010 compared to 2009 as a result of increased recoverable fuel costs billed to customers through the FAC due to higher fuel prices.

The decrease in the FAC revenue during 2009 compared to 2008 resulted from lower fuel costs billed to customers through the FAC ($2 million) due to a refund of power purchased costs from OMU ($6 million) partially offset by increased recoverable fuel costs ($4 million) billed to retail customers through the FAC.

(f) The decrease in wholesale sales during 2010 compared to 2009 was primarily due to increased consumption by industrial customers, as a result of improved economic conditions, increased consumption by residential customers, as a result of increased cooling and heating degree days and an increase in LG&E's coal-fired generation outages in the first six months of 2010. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between KU and LG&E.

The decrease in wholesale sales during 2009 compared to 2008 was primarily due to lower sales volumes to LG&E and third-parties due to lower economic capacity, caused by low spot market pricing and higher scheduled coal-fired generation outages. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between KU and LG&E.

Operating Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority. Operating expenses and the changes therein for 2010, 2009 and 2008 follow:

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Fuel for electric generation	$ 495	$ 78	$ 417	$ 434	$ 513
Power purchased	175	28	147	199	221
Other operation and maintenance expenses	346	66	280	320	275
Depreciation and amortization	145	26	119	133	136
	$ 1,161	$ 198	$ 963	$ 1,086	$ 1,145

The changes in operating expenses were as follows:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Fuel for electric generation	$ 61	$ (79)
Power purchased	(24)	(22)
Other operation and maintenance expenses	26	45
Depreciation and amortization	12	(3)
	$ 75	$ (59)

Fuel for Electric Generation

The $61 million increase from 2009 to 2010 and $79 million decrease from 2008 to 2009 were primarily due to:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Fuel usage volumes (a)	$ 77	$ (97)
Commodity costs for coal	(15)	18
Other	(1)	-
	$ 61	$ (79)

(a) Fuel usage volumes increased in 2010 compared 2009 due to increased native load sales. Fuel usage volumes decreased in 2009 compared to 2008 due to decreased native load and wholesale sales.

Power Purchased Expense

The $24 million decrease from 2009 to 2010 and $22 million decrease from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Power purchased from OMU	$ (40)	$ 12
Purchases from LG&E due to volume (a)	(5)	(2)
Demand payments for third party purchases	(2)	1
Prices for purchases used to serve retail customers	7	(14)
Third party purchased volumes for native load (b)	7	(6)
OMU settlement received in 2009	6	(6)
Purchases from LG&E due to prices	3	(7)
	$ (24)	$ (22)

(a) Purchased volumes from LG&E decreased in 2010 compared to 2009 primarily due to increased consumption by residential customers at LG&E as the result of increased cooling and heating degree days, increased coal-fired generation outages in the first six months of 2010 and higher energy usage by industrial customers as a result of improved economic conditions.

Purchased volumes from LG&E decreased in 2009 compared to 2008 due to LG&E's increased scheduled outages at coal-fired generation units during the fourth quarter of 2009. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between the Utilities.

(b) Third party purchase volumes with counterparties other than OMU increased in 2010 compared to 2009 primarily due to the termination of the OMU agreement. Third party purchase volumes with counterparties other than OMU decreased in 2009 compared to 2008 primarily due to availability of power for native load customers from the OMU agreement. See Note 13, Commitments and Contingencies, for further discussion of the OMU settlement.

Other Operation and Maintenance Expenses

The $26 million increase from 2009 to 2010 was primarily due to $22 million of increased other operation expenses and $4 million of increased maintenance expenses. The $45 million increase from 2008 to 2009 was primarily due to $30 million of increased other operation expenses and $15 million of increased maintenance expenses.

Other Operation Expenses:

The $22 million increase from 2009 to 2010 and $30 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Administrative and general expense (a)	$ 9	$ 3
Transmission expense (b)	5	-
Bad debt expense (c)	4	(1)
Steam expense (d)	4	7
Generation expense	2	(2)
DSM program spending	-	9
Legal expenses (e)	-	(6)
Other power supply	(1)	-
Pension expense (f)	(2)	20
Other	1	-
	$ 22	$ 30

(a) Administrative and general expense increased in 2010 compared 2009 primarily due to higher labor expense and insurance expense, partially offset by lower IT expense related to the implementation of the Customer Care Solution system in 2009. Administrative and general expense increased in 2009 compared to 2008 primarily due to increased consulting fees for software training and increased labor and benefit costs.

(b) Transmission expense increased in 2010 compared to 2009 primarily due to a settlement agreement with a third party and the establishment of a regulatory asset approved by the Kentucky Commission for the EKPC settlement in 2009, net of twelve months of amortization expense recorded in 2010.

(c) Bad debt expense increased in 2010 compared to 2009 due to higher billed revenues, higher late payment charges and a higher net charge-off percentage.

(d) Steam expense increased in 2010 compared to 2009 primarily due to increased generation in 2010. Steam expense increased in 2009 compared to 2008 primarily due to the utilization of SCRs year-round.

(e) Legal expenses decreased in 2009 compared to 2008 primarily due to OMU expenses in 2008. See Note 13, Commitments and Contingencies, for further information regarding the OMU settlement.

(f) Pension expense decreased in 2010 compared to 2009 primarily due to favorable asset performance in 2009 and increased in 2009 compared to 2008 primarily due to unfavorable asset performance in 2008.

Other Maintenance Expenses:

The $4 million increase from 2009 to 2010 and $15 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Generation expense (a)	$ 3	$ -
Steam expense (b)	2	7
Administrative and general expense	2	1
Transmission expense	-	2
Distribution expense (c)	(3)	5
	$ 4	$ 15

(a) Generation expense increased in 2010 compared to 2009 primarily due to the overhaul of Paddy's Run Unit 13.
(b) Steam expense increased in 2009 compared to 2008 due to increased scope of work for scheduled outages.
(c) Distribution expense decreased in 2010 compared to 2009 primarily due to higher storm cost in 2009, partially offset by higher tree trimming expense in 2010. Distribution expense increased in 2009 compared to 2008 primarily due to increased repairs, higher tree trimming expense and higher storm related expense.

Equity in Earnings of Unconsolidated Venture

The $2 million increase in equity in earnings of unconsolidated venture, from 2009 to 2010, was primarily due to higher earnings from EEI resulting from increased market prices for electric energy and the $29 million decrease from 2008 to 2009 was primarily due to lower earnings resulting from decreased market prices for electric energy.

Interest Expense

The $3 million increase from 2009 to 2010 and $3 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Bond interest expense (a)	$ 8	$ (8)
Interest expense to affiliated companies (b)	(5)	11
	$ 3	$ 3

(a) Bond interest expense increased in 2010 compared to 2009 due to the issuance of first mortgage bonds in November 2010. Bond interest expense decreased in 2009 compared to 2008 due to lower interest rates on pollution control bonds. See Note 11, Long-Term Debt, for further information.
(b) Interest expense to affiliated companies decreased in 2010 compared to 2009 primarily due to notes payable to Fidelia being paid in full in November 2010, as a result of the PPL acquisition. Interest expense to affiliated companies increased in 2009 compared to 2008 primarily due to the

issuance of additional debt ($13 million), which was partially offset by lower interest rates on intercompany short-term borrowings.

Other Income (Expense) – Net

The $7 million decrease in other income (expense) – net from 2009 to 2010 and the $3 million decrease in other income (expense) – net from 2008 to 2009 were primarily due to the discontinuance of the allowance for funds used during construction on ECR projects as a result of the FERC rate case.

Income Tax Expense

See Note 10, Income Taxes, for a reconciliation of differences between the U.S. federal income tax expense at statutory rates and KU's income tax expense.

2011 Outlook

KU projects higher earnings in 2011 compared with 2010 as a net result of higher retail revenues and lower financing costs due to the issuance of first mortgage bonds in late 2010, partially offset by higher operation and maintenance expenses and depreciation. Retail revenues are expected to increase as a result of the 2010 Kentucky rate case and recoveries associated with its environmental investments. Operation and maintenance expenses and depreciation are expected to increase due to placing TC2 in service in January 2011. See Risk Factors for a discussion of the risk factors that may impact the 2011 outlook.

Financial Condition

Liquidity and Capital Resources

KU expects to continue to have adequate liquidity available through operating cash flows, cash and cash equivalents and its credit facilities. KU currently has no plans to access debt capital markets in 2011.

KU's cash flows from operations and access to cost-effective bank and capital markets are subject to risks and uncertainties including, but not limited to, the following:

- changes in market prices for electricity;
- potential ineffectiveness of the trading, marketing and risk management policy and programs used to mitigate KU's risk exposure to adverse electricity and fuel prices and interest rates;
- operational and credit risks associated with selling and marketing products in the wholesale power markets;
- unusual or extreme weather that may damage KU's transmission and distribution facilities or affect energy sales to customers;
- unavailability of generating units (due to unscheduled or longer than anticipated generation outages, weather and natural disasters) and the resulting loss of revenues and additional costs of replacement electricity;
- ability to recover and timeliness and adequacy of recovery of costs;
- costs of compliance with existing and new environmental laws;

- any adverse outcome of legal proceedings and investigations with respect to KU's current and past business activities;
- deterioration in the financial markets that could make obtaining new sources of bank and capital markets funding more difficult and more costly; and
- a downgrade in KU's credit ratings that could adversely affect its ability to access capital and increase the cost of credit facilities and any new debt.

See the Risk Factors section for further discussion of risks and uncertainties affecting KU's cash flows.

At December 31, KU had the following:

	Successor 2010	Predecessor 2009
Cash and cash equivalents	$ 3	$ 2
Current portion of long-term debt (a)	$ -	$ 228
Current portion of long-term debt to affiliated company (b)	-	33
Notes payable to affiliated companies (c)	10	45
	$ 10	$ 306

(a) 2009 amount represents Carroll County 2002 Series A and B, 2004 Series A, 2006 Series B and 2008 Series A; Muhlenberg County 2002 Series A; and Mercer County 2000 Series A and 2002 Series A pollution control bonds subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. The Successor has classified these bonds as long-term because the Company has the intent and ability to utilize its $400 million credit facility which matures in December 2014, to fund any mandatory purchases. The Predecessor classified these bonds as the current portion of long-term debt due to the tender for purchase provisions. The Predecessor presentation and the Successor presentation are both appropriate under GAAP. See Note 1, Summary of Significant Accounting Policies, and Note 11, Long-Term Debt, for further information.

(b) 2009 amount represents debt owed to an E.ON affiliate, which was repaid in November 2010. See Note 11, Long-Term Debt, for further information.

(c) Amounts represent borrowings under KU's intercompany money pool agreement wherein LKE and/or LG&E make funds available to KU at market-based rates of up to $400 million. See Note 12, Notes Payable and Other Short-Term Obligations, for further information.

A condensed table of cash flows for the following periods in 2010, 2009 and 2008 is presented below. The Predecessor period, January 1, 2010 through October 31, 2010, and the Successor period, November 1, 2010 through December 31, 2010, were aggregated without further adjustment for purposes of comparison with the same periods in 2009 and 2008.

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Net cash provided by (used in) operating activities	$ 372	$ 28	$ 344	$ 253	$ 292
Net cash provided by (used in) investing activities	(427)	(87)	(340)	(507)	(695)
Net cash provided by (used in) financing activities	56	58	(2)	254	405
Change in cash and cash equivalents	$ 1	$ (1)	$ 2	$ -	$ 2

Operating Activities

Net cash provided by operating activities increased by 47%, or $119 million, in 2010 compared with 2009, primarily as a result of increased earnings, increased collections from the ECR mechanism and lower storm expenses. These increases in cash flow were partially offset by higher interest payments due to an accelerated settlement with the previous owner and higher 2010 income tax payments due to higher taxable income and investment tax credit benefits received in 2009.

Net cash provided by operating activities decreased by 13%, or $39 million, in 2009 compared with 2008, primarily as a result of higher storm expenses, decreased earnings and unfavorable changes in working capital. These decreases in cash flow were partially offset by lower income tax payments due to lower taxable income and investment tax credit benefits received.

KU expects to achieve relatively stable cash flows from operations during the next three years although future cash flows may be significantly impacted by changes in economic conditions or new environmental and tax regulations.

Investing Activities

The primary use of cash in investing activities is capital expenditures. See “Forecasted Uses of Cash" for detail regarding projected capital expenditures for the years 2011 through 2013.

Net cash used in investing activities decreased by 16%, or $80 million, in 2010 compared with 2009, primarily as a result of a decrease of $89 million in capital expenditures, partially offset by a decrease of $9 million from restricted cash collections.

Net cash used in investing activities decreased by 27%, or $188 million, in 2009 compared with 2008, primarily as a result of a decrease of $180 million in capital expenditures and a increase of $8 million from restricted cash collections.

Financing Activities

Net cash provided by financing activities was $56 million in 2010 compared with $254 million in 2009. In spite of significant new debt issuances associated with the repayments to E.ON affiliates in connection with PPL's acquisition of the Company, cash provided by financing was less in 2010 due to lower increases in debt in 2010 and the payment of dividends in 2010; whereas, KU received equity contributions in 2009.

Net cash provided by financing activities was $254 million in 2009 compared with $405 million in 2008. The lower level of cash provided by financing in 2009 was the result of lower debt issuance to affiliated companies and lower levels of equity contributions received.

In the two months of 2010 following the acquisition, cash provided by financing activities of the Successor primarily consisted of the issuance of first mortgage bonds totaling $1,489 million after discounts and the issuance of intercompany notes totaling $1,331 million to a PPL subsidiary to repay debt due to an E.ON affiliate upon the closing of the sale. These amounts were offset by the repayment of $1,331 million to an E.ON affiliate upon the closing of the sale, the repayment of $1,331 million to a PPL affiliate upon the issuance of the first mortgage bonds, the repayment of $83 million of short-term borrowings due to an affiliated company and the payment of $17 million of debt issuance costs.

In 2010, cash used in financing activities by the Predecessor primarily consisted of the payment of $50 million of dividends to LKE mostly offset by increases in short-term borrowings due to an affiliated company totaling $48 million.

In 2009, cash provided by financing activities primarily consisted of the issuance of $150 million of intercompany notes to an E.ON affiliate, the receipt of capital contributions from LKE totaling $75 million and a $29 million increase in short-term borrowings due to an affiliated company.

In 2008, cash provided by financing activities primarily consisted of the issuance of $250 million of intercompany notes to an E.ON affiliate, the receipt of capital contributions from LKE totaling $145 million and a $7 million reduction in short-term borrowings due to an affiliated company. In addition, KU reacquired pollution control bonds totaling $80 million, reissued $63 million of that $80 million and issued $77 million of new pollution control bonds. Of the $77 million, $60 million was used to retire prior pollution control bonds, including the remaining $17 million which had been reacquired by the Company. This resulted in a cash receipt of $17 million to KU.

KU's debt financing activity in 2010 was:

	Issuances (a)	Retirements
Short-term borrowings from affiliated company – net change	$ -	$ (35)
Other borrowings from affiliated company	1,331	(1,331)
Borrowings from an E.ON affiliate	-	(1,331)
Issuance of bonds	1,489	-
Net change in debt financing	$ 2,820	$ (2,697)

(a) Issuances are net of pricing discounts, where applicable.

See Note 11, Long-Term Debt, for further information.

Working Capital Deficiency

As of December 31, 2009, KU had a working capital deficiency of $203 million, primarily due to the current portion of long-term debt to affiliated company totaling $33 million and $228 million of tax-exempt bonds which allow the investors to put the bonds back to the Company causing them to be classified as "Current portion of long-term debt." As of December 31, 2010, the Company no longer had a working capital deficiency because the current portion of long-term debt to affiliated company was paid off in conjunction with the PPL acquisition, and the $228 million of tax-exempt bonds were no longer classified as "Other current liabilities" by the Successor because the Company has the intent and ability to utilize its $400 million credit facility which expires in December 2014 to fund any mandatory purchases. See Note 11, Long-Term Debt, for further information.

Auction Rate Securities

Auctions for auction rate securities issued by KU continued to fail throughout 2010. See Note 11, Long-Term Debt, for further discussion.

Forecasted Sources of Cash

KU expects to continue to have adequate sources of cash available in the near term, including access to external financing, financing from affiliates and/or infusions of capital from LKE. Regulatory approvals are required for KU to incur additional debt. The FERC and the Virginia Commission authorize the issuance of short-term debt while the Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority authorize the issuance of long-term debt. In November 2009, KU received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. KU also has authorization from the Virginia Commission that expires at the end of 2011, allowing short-term borrowing of up to $400 million. Short-term funds are made available via the Company's participation in an intercompany money pool agreement wherein LKE and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) up to $400 million or via the $400 million Revolving Credit Agreement discussed below. KU currently believes this authorization and these facilities, together with the Company's credit facilities discussed below, provide the necessary flexibility to address any liquidity needs.

Credit Facilities

On November 1, 2010, KU entered into a $400 million unsecured Revolving Credit Agreement with a group of banks. Under this new credit facility, which expires on December 31, 2014, KU has the ability to make cash borrowings and to request the lenders to issue letters of credit. Borrowings will generally bear interest at LIBOR-based rates plus a spread, depending upon KU's senior unsecured long-term debt rating. The new credit facility contains financial covenants requiring KU's debt to total capitalization to not exceed 70% and other customary covenants. As of December 31, 2010, KU's debt to total capitalization was 41% as calculated pursuant to the credit agreement. Under certain conditions, KU may request that the facility's capacity be increased by up to $100 million. This new credit facility

replaced an existing bilateral line of credit totaling $35 million that was terminated November 1, 2010. As of December 31, 2010, there was no outstanding balance under the new credit facility, but there were $198 million of letters of credit outstanding to support outstanding bonds totaling $195 million. KU will utilize unused credit facility and money pool balances to fund working capital needs as they arise. See Note 12, Notes Payable and Other Short-Term Obligations, for further information regarding the Company's credit facilities.

Contributions from LKE

LKE may make capital contributions to KU, which can be used for general business purposes.

Long-Term Debt

KU currently does not plan to issue any new long-term debt in 2011.

Forecasted Uses of Cash

In addition to expenditures required for normal operating activities, such as fuel for electric generation, power purchased, payroll and taxes; KU currently expects to incur future cash outflows for capital expenditures, various contractual obligations and the payment of dividends.

Capital Requirements

KU's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of its service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. KU plans to fund capital expenditures through operating cash flows, the credit facility and, if needed, the issuance of long-term debt. KU expects its capital expenditures for the three year period ending December 31, 2013, to total approximately $1,406 million, consisting primarily of the following:

Construction of coal combustion residual storage structures	$ 346
Construction of environmental controls and capacity replacement	302
Construction of distribution and metering assets	260
Construction of generation assets	206
Construction of transmission assets	129
Recoverable environmental assets	99
Information technology projects	39
Other projects	25
	$ 1,406

The Company's capital program will focus primarily on compliance with existing or anticipated EPA environmental regulations, aging infrastructure and the need for increased storage capacity for coal combustion by-product materials over the next several years. This program may also be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, changes in commodity prices and labor rates and other regulatory requirements. In particular, climate change initiatives, whether via legislative, regulatory or market channels, could restrict or disadvantage power generation from higher-

carbon sources. Therefore, KU has included estimates regarding significant additional capital expenditures related to pending environmental regulations and legislation. These estimates are subject to final regulations and least cost analysis based on engineering studies. To the extent financial markets see climate change as a potential risk, KU may face reduced access to or increased costs in capital markets. Capital expenditures for KU associated with such actions are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary.

See the Contractual Obligations table below and Note 13, Commitments and Contingencies, for further information concerning commitments.

Contractual Obligations

The following is provided to summarize contractual cash obligations for periods after December 31, 2010. KU anticipates cash from operations and external financing will be sufficient to fund future obligations. See the Statements of Capitalization.

	Payments Due by Period						
	2011	2012	2013	2014	2015	Thereafter	Total
Short-term debt (a)	$ 10	$ -	$ -	$ -	$ -	$ -	$ 10
Long-term debt (b)	-	-	-	-	250	1,601	1,851
Interest on long-term debt (c)	67	69	72	75	78	1,414	1,775
Operating leases (d)	8	7	5	5	3	1	29
Unconditional power purchase obligations (e)	9	10	10	10	10	114	163
Coal and natural gas purchase obligations (f)	439	200	144	93	91	14	981
Pension benefit plan obligations (g)	18	24	28	10	7	60	147
Postretirement benefit plan obligations (h)	5	6	6	6	6	33	62
Construction obligations (i)	113	3	-	-	-	-	116
Other obligations (j)	3	3	-	-	-	-	6
	$ 672	$ 322	$ 265	$ 199	$ 445	$ 3,237	$ 5,140

This table does not reflect contingent obligations. See Note 13, Commitments and Contingencies, for further information on contingent obligations.

(a) Represents borrowings due to affiliates within one year.
(b) Reflects principal maturities only based on legal maturity dates and includes the current portion of long-term debt.
(c) Assumes interest payments through maturity. The payments herein are subject to change as payments for debt that is or becomes variable-rate debt have been estimated.
(d) Represents future operating lease payments.
(e) Represents future minimum payments under OVEC power purchase agreements through March 13, 2026.
(f) Represents contracts to purchase coal, natural gas and natural gas transportation.

(g) Represents projected cash flows for funding the pension benefit plans as calculated by the actuary. For pension funding information see Note 9, Pension and Other Postretirement Benefit Plans.
(h) Represents projected cash flows for the postretirement benefit plan as calculated by the actuary. For postretirement funding information, see Note 9, Pension and Other Postretirement Benefit Plans.
(i) Represents construction commitments, including commitments for the Brown SCR and the Brown and Ghent landfill construction including associated material transport systems for coal combustion residual.
(j) Represents other contractual obligations including the SPP and TVA coordination agreements.

Pension and Postretirement Benefit Plans

See Application of Critical Accounting Policies and Estimates for discussion regarding discretionary contributions to the pension and postretirement benefit plans in 2011.

Dividends

Future dividends may be declared at the discretion of KU's Board of Directors, payable to its sole shareholder, LKE. As discussed in Note 12, Notes Payable and Other Short-Term Obligations, KU's dividend payments are limited under a covenant in its $400 million revolving line of credit facility. This covenant restricts the debt to total capital ratio to not more than 70%. KU is subject to Section 305(a) of the Federal Power Act, which makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in capital account." The meaning of this limitation has never been clarified under the Federal Power Act. KU believes, however, that this statutory restriction, as applied to its circumstances, would not be construed or applied by the FERC to prohibit the payment from retained earnings of dividends that are not excessive and are for lawful and legitimate business purposes.

Purchase, Redemption or Remarketing of Debt Securities

KU will continue to evaluate purchasing, redeeming or remarketing outstanding debt securities and may decide to take action depending upon prevailing market conditions and available cash.

Credit Ratings

KU's credit ratings reflect the views of three national rating agencies. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. In October 2010, one national rating agency revised downward the short-term credit rating of the pollution control bonds and the issuer rating of the Company as a result of the then pending acquisition by PPL. Another raised the long-term rating of the pollution control bonds as a result of the addition of the first mortgage bonds as collateral. In October 2010, a third national rating agency provided an initial rating of the Company's pollution control bonds and first mortgage bonds. See Note 11, Long-Term Debt, for a discussion of downgrade actions in 2009 and 2008 related to the pollution control bonds caused by a change in the rating of the entity insuring those bonds.

Ratings Triggers

KU has various derivative and non-derivative contracts, including contracts for the sale and purchase of electricity and fuel and commodity transportation, which contain provisions requiring KU to post additional collateral, or permit the counterparty to terminate the contract if KU's credit rating were to fall below investment grade. See Note 5, Derivative Financial Instruments, for a discussion of Credit Risk Related Contingent Features, including a discussion of the potential additional collateral that would have been required for derivative contracts in a net liability position at December 31, 2010. At December 31, 2010, if KU's credit ratings had been below investment grade, KU would have been required to prepay or post an additional $16 million of collateral to counterparties for both derivative and non-derivative commodity and commodity-related contracts used in its generation, marketing and trading operations.

Off-Balance Sheet Arrangements

KU has very limited off-balance sheet activity. See Note 13, Commitments and Contingencies, for further discussion.

Risk Management

Credit Risk

KU is exposed to potential losses as a result of nonperformance by counterparties of their contractual obligations. KU maintains credit policies and procedures to limit counterparty credit risk including evaluating credit ratings and financial information along with having certain counterparties post margin if the credit exposure exceeds certain thresholds. See Note 5, Derivative Financial Instruments, for information regarding risk management activities.

KU is exposed to potential losses as a result of nonpayment by customers. The Company maintains an allowance for doubtful accounts composed of accounts aged more than four months. Accounts are written off as management determines them uncollectible. See Application of Critical Accounting Policies and Estimates and Note 1, Summary of Significant Accounting Policies, for further discussion.

Certain of the Company's derivative instruments contain provisions that require it to provide immediate and on-going collateralization on derivative instruments in net liability positions based upon the Company's credit ratings from each of the major credit rating agencies. See Note 5, Derivative Financial Instruments, for information regarding exposure and the risk management activities.

Liquidity Risk

KU expects to continue to have access to adequate sources of liquidity through operating cash flows, cash and cash equivalents, credit facilities and/or infusion of capital from its parent. See Financial Condition - Liquidity and Capital Resources for an expanded discussion of KU's liquidity position and a discussion of its forecasted sources of cash.

Securities Price Risk

KU has securities price risk through its participation in defined benefit pension and postretirement benefit plans. Declines in the market price of debt and equity securities could impact contribution requirements. See Application of Critical Accounting Policies and Estimates - Defined Benefits for a discussion of the assumptions and sensitivities regarding the defined benefit pension and postretirement benefit plans assumptions.

Interest Rate and Commodity Price Risk

KU is subject to interest rate and commodity price risk related to on-going business operations. It currently manages commodity risks using derivative instruments, including swaps and forward contracts. The Company's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At December 31, 2010, no interest rate swaps were in effect for KU. At December 31, 2010, the Company's annual exposure to increased interest expense, based on a 10% increase in interest rates, was less than $1 million.

KU manages price risk by conducting energy trading activities through forward financial transactions. The following chart sets forth the net fair value of KU's commodity derivative contracts. See Note 5 Derivative Financial Instruments, for further information.

	Successor	Predecessor	
	December 31, 2010 (a)	October 31, 2010 (a)	December 31, 2009
Fair value of contracts outstanding at the beginning of the period	$ -	$ -	$ 1
Contracts realized or otherwise settled during the period	-	-	
Fair value of new contracts entered into during the period	-	-	-
Changes in fair value attributable to changes in valuation techniques	-	-	-
Other changes in fair value	-	-	(1)
Fair value of contracts outstanding at the end of the period	$ -	$ -	$ -

(a) 2010 activity is less than $1 million.

Related Party Transactions

KU and its Parent, LKE and subsidiaries of LKE engage in related party transactions. See Note 15, Related Party Transactions, for further information.

KU is not aware of any material ownership interest or operating responsibility by the executive officers of KU in outside partnerships, including leasing transactions with variable interest entities, or entities doing business with KU.

Acquisitions, Development and Divestitures

KU and LG&E have been constructing a new 760-Mw capacity base-load, coal-fired unit, TC2, which is jointly owned by KU (60.75%) and LG&E (14.25%), together with IMEA and IMPA (combined 25%). With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. See Note 13, Commitments and Contingencies, for further information.

KU continuously re-examines development projects based on market conditions and other factors to determine whether to proceed, to cancel or to expand the projects.

Application of Critical Accounting Policies and Estimates

The financial statements of KU are prepared in compliance with GAAP. The application of these principles necessarily involves judgments regarding future events, including legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but also on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied has not changed. KU's senior management has reviewed the significant and critical accounting policies with the relevant governing bodies of the Company and its parent, as applicable.

An accounting policy is deemed to be critical if it requires an accounting estimate to be made based on assumptions about matters that are highly uncertain at the time the estimate is made, if different estimates reasonably could have been used or if changes in the estimate that are reasonably possible could materially impact the financial statements. Management believes the following critical accounting policies reflect the significant estimates and assumptions used in the preparation of the Financial Statements.

Price Risk Management

See Financial Condition - Risk Management.

Regulatory Mechanisms

KU is a cost-based rate-regulated utility. As a result, the financial statements reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise be charged to expense. Likewise, regulatory liabilities are recognized for obligations expected to be returned through future regulated customer rates. The effect of such transactions or events would otherwise be reflected as income. In certain cases, regulatory liabilities are recorded based on the understanding with the regulator that current rates are being set to recover costs that are expected to be incurred in the future. The regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. The accounting

for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC, the Kentucky Commission, the Virginia Commission or the Tennessee Regulatory Authority. See Note 3, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Defined Benefits

KU employees benefit from both funded and unfunded retirement benefit plans. See Note 1, Summary of Significant Accounting Policies, for information about policy changes between the Predecessor and Successor and the accounting for defined benefits including KU's method of amortizing gains and losses. KU makes various assumptions in arriving at pension and other postretirement benefit costs and obligations. The major assumptions include:

- KU's selection of discount rates is based on the Mercer Pension Discount Yield Curve (Predecessor) and the Towers Watson Yield Curve (Successor).
- KU's selection of rate of salary growth is based on historical data that includes employees' periodic pay increases and promotions, which are used to project employees' pension benefits at retirement.
- KU determines the expected long-term return on plan assets based on the current level of expected return on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class is then weighted based on the current asset allocation.
- KU's management projects health care cost trends based on past health care costs, the near-term outlook and an assessment of likely long-term trends.

The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under the defined benefit pension plans. The return on investments within the plans was approximately 12% for the year ended December 31, 2010. The benefit plan assets and obligations are re-measured annually using a December 31 measurement date. Due to the PPL acquisition, the benefit plan assets and obligations were also re-measured at October 31, 2010. The Company's 2010 pension cost was approximately $3 million less than 2009. The Company anticipates its 2011 pension cost will be approximately $3 million less than the 2010 expense. The amount of future funding will depend upon the actual return on plan assets, the discount rate and other factors, but the Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. The Company made discretionary contributions to its pension plan of $13 million in 2010 and 2009, respectively. In January 2011, KU contributed $43 million to its pension plan. See Note 18, Subsequent Events, for further information.

See Note 9, Pension and Other Postretirement Benefit Plans, for further information on defined benefits including sensitivity analysis expressing potential changes in expected returns that would result from hypothetical changes to assumptions and estimates, expected rate of return assumptions and health care trends.

Asset Impairment

KU performs a quarterly review to determine if an impairment analysis is required for long-lived assets that are subject to depreciation or amortization. This review identifies changes in circumstances indicating that a long-lived asset's carrying value may not be recoverable. An impairment analysis will be performed if warranted based on the review. For these long-lived assets, such events or changes in circumstances which may indicate an impairment analysis is required include:

- a significant decrease in the market price of an asset;
- a significant adverse change in the manner in which an asset is being used or in its physical condition;
- a significant adverse change in legal factors or in the business climate;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of an asset;
- a current-period operating or cash flow loss combined with a history of losses or a forecast that demonstrates continuing losses;
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its previously estimated useful life; and
- a significant change in the physical condition of an asset.

For a long-lived asset, impairment is recognized when the carrying amount of the asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset is impaired, an impairment loss is recorded to adjust the asset's carrying value to its estimated fair value. Management must make significant judgments to estimate future cash flows including the useful lives of long-lived assets, the fair value of the assets and management's intent to use the assets. KU did not recognize an impairment of any long-lived asset in 2010.

Effective with PPL's acquisition of LKE on November 1, 2010, KU recorded $607 million of goodwill. At December 31, 2010, KU's goodwill remained unchanged. GAAP requires goodwill to be tested for impairment on an annual basis or more frequently if events or circumstances indicate that assets may be impaired. KU performs its annual goodwill impairment test in the fourth quarter. See Note 7, Goodwill and Intangible Assets, for further discussion.

Goodwill is tested for impairment using a two-step approach. In step 1, the Company identifies a potential impairment by comparing the estimated fair value of the Company (the goodwill reporting unit) to its carrying value, including goodwill, on the measurement date. If the estimated fair value exceeds its carrying amount, goodwill is not considered impaired. If the carrying amount exceeds the estimated fair value, the second step is performed to measure the amount of impairment loss, if any.

The second step requires a calculation of the implied fair value of goodwill. The implied fair value of goodwill is determined in the same manner as the amount of goodwill in a business combination. That is, the estimated fair value is allocated to all of KU's assets and liabilities as if KU had been acquired in a business combination and the estimated fair value of KU was the price paid. The excess of the estimated fair value of KU over the amounts assigned to its assets and liabilities is the implied fair value of goodwill. The implied fair value of goodwill is then compared with the carrying amount of that goodwill. If the

carrying amount exceeds the implied fair value, an impairment loss is recognized in an amount equal to that excess. The loss recognized cannot exceed the carrying amount of the reporting unit's goodwill.

Determining the fair value of KU is judgmental in nature and involves the use of significant estimates and assumptions. These estimates and assumptions can include revenue growth rates and operating margins used to calculate projected future cash flows, risk adjusted discount rates and future economic and market conditions.

KU tested goodwill for impairment in the fourth quarter of 2010 and no impairment was recognized. See Note 7, Goodwill and Intangible Assets, for further discussion.

Loss Accruals

KU accrues losses for the estimated impacts of various conditions, situations or circumstances involving uncertain or contingent future outcomes. For loss contingencies, the loss must be accrued if (1) information is available that indicates it is probable that a loss has been incurred, given the likelihood of the uncertain future events and (2) the amount of the loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." KU does not record the accrual of contingencies that might result in gains, unless recovery is assured. KU continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events.

The accounting aspects of estimated loss accruals include (1) the initial identification and recording of the loss, (2) the determination of triggering events for reducing a recorded loss accrual and (3) the ongoing assessment as to whether a recorded loss accrual is sufficient. All three of these aspects require significant judgment by KU's management. KU uses its internal expertise and outside experts (such as lawyers and engineers), as necessary, to help estimate the probability that a loss has been incurred and the amount or range of the loss.

KU has identified certain other events that could give rise to a loss, but that do not meet the conditions for accrual. Such events are disclosed, but not recorded, when it is reasonably possible that a loss has been incurred. Accounting guidance defines "reasonably possible" as cases in which "the future event or events occurring is more than remote, but less than likely to occur." See Note 13, Commitments and Contingencies, for disclosure of other potential loss contingencies that have not met the criteria for accrual.

When an estimated loss is accrued, KU identifies, where applicable, the triggering events for subsequently adjusting the loss accrual. The triggering events generally occur when the contingency has been resolved and the actual loss is incurred, or when the risk of loss has diminished or been eliminated. The following are some of the triggering events that provide for the adjustment of certain recorded loss accruals:

- Allowances for uncollectible accounts are reduced when accounts are written off after prescribed collection procedures have been exhausted, a better estimate of the allowance is determined or underlying amounts are ultimately collected.
- Environmental and other litigation contingencies are reduced when the contingency is resolved, KU makes actual payments, a better estimate of the loss is determined or the loss is no longer considered probable.

KU reviews its loss accruals on a regular basis to assure that the recorded potential loss exposures are appropriate. This involves ongoing communication and analyses with internal and external legal counsel, engineers, operation management and other parties. This review may result in the increase or decrease of the loss accrual.

Asset Retirement Obligations

KU is required to recognize a liability for legal obligations associated with the retirement of long-lived assets. The initial obligation is measured at its estimated fair value. An equivalent amount is recorded as an increase in the value of the capitalized asset and allocated to expense over the useful life of the asset. Until the obligation is settled, the liability is increased, through the recognition of accretion expense in the Statements of Income, for changes in the obligation due to the passage of time. An offsetting regulatory asset is recognized to reverse the depreciation and accretion expense related to the ARO such that there is no income statement impact. The regulatory asset is relieved when the ARO has been settled. An ARO must be recognized when incurred if the fair value of the ARO can be reasonably estimated.

In determining AROs, management must make significant judgments and estimates to calculate fair value. Fair value is developed using an expected present value technique based on assumptions of market participants that considers estimated retirement costs in current period dollars that are inflated to the anticipated retirement date and then discounted back to the date the ARO was incurred. Changes in assumptions and estimates included within the calculations of the fair value of AROs could result in significantly different results than those identified and recorded in the financial statements. Estimated ARO costs and settlement dates, which affect the carrying value of various AROs and the related assets, are reviewed periodically to ensure that any material changes are incorporated into the estimate of the obligations. Any change to the capitalized asset is amortized over the remaining life of the associated long-lived asset. See Note 4, Asset Retirement Obligations, for further information on AROs.

At December 31, 2010, KU had AROs totaling $54 million recorded on the Balance Sheets. Of the total amount, $35 million, or 65%, relates to KU's ash ponds and landfills. The most significant assumptions surrounding AROs are the forecasted retirement costs, the discount rates and the inflation rates. A variance in the forecasted retirement costs, the discount rates or the inflation rates could have a significant impact on the ARO liabilities.

The following chart reflects the sensitivities related to KU's ARO liabilities for ash ponds and landfills as of December 31, 2010:

	Change in Assumption	Impact on ARO Liability
Retirement cost	10%/(10)%	$4/$(4)
Discount rate	0.25%/(0.25)%	$(2)/$1
Inflation rate	0.25%/(0.25)%	$2/$(2)

Income Tax Uncertainties

Significant management judgment is required in developing KU's provision for income taxes primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and the determination of deferred tax assets, liabilities and valuation allowances.

Significant management judgment is required to determine the amount of benefit recognized related to an uncertain tax position. KU evaluates its tax positions following a two-step process. The first step requires an entity to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires an entity to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. KU's management considers a number of factors in assessing the benefit to be recognized, including negotiation of a settlement.

On a quarterly basis, KU reassesses its uncertain tax positions by considering information known at the reporting date. Based on management's assessment of new information, KU may subsequently recognize a tax benefit for a previously unrecognized tax position, de-recognize a previously recognized tax position or re-measure the benefit of a previously recognized tax position. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact KU financial statements in the future.

The balance sheet classification of unrecognized tax benefits and the need for valuation allowances to reduce deferred tax assets also require significant management judgment. KU classifies unrecognized tax benefits as current, to the extent management expects to settle an uncertain tax position, by payment or receipt of cash, within one year of the reporting date. Valuation allowances are initially recorded and reevaluated each reporting period by assessing the likelihood of the ultimate realization of a deferred tax asset. Management considers a number of factors in assessing the realization of a deferred tax asset, including the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies. Any tax planning strategy utilized in this assessment must meet the recognition and measurement criteria utilized by KU to account for an uncertain tax position. See Note 10, Income Taxes, for the required disclosures.

At December 31, 2010, KU's existing reserve exposure to either increases or decreases in unrecognized tax benefits during the next 12 months is less than $1 million. This change could result from subsequent recognition, de-recognition and/or changes in the measurement of uncertain tax positions. The events that could cause these changes are direct settlements with taxing authorities, litigation, legal or administrative guidance by relevant taxing authorities and the lapse of an applicable statute of limitations.

Purchase Price Allocation

On November 1, 2010, PPL completed the acquisition of KU's parent. In accordance with accounting guidance on business combinations, the identifiable assets acquired and the liabilities assumed were measured at fair value at the acquisition date. Fair value is defined as the price that would be received to

sell an asset or paid to transfer a liability in an orderly transaction between market participants. The excess of the purchase price over the estimated fair value of the identifiable net assets is recorded as goodwill.

The determination and allocation of fair value to the identifiable assets acquired and liabilities assumed was based on various assumptions and valuation methodologies requiring considerable management judgment, including estimates based on key assumptions of the acquisition and historical and current market data. The most significant variables in these valuations were the discount rates, the number of years on which to base cash flow projections, as well as the assumptions and estimates used to determine cash inflows and outflows. Although the assumptions applied were reasonable based on information available at the date of acquisition, actual results may differ from the forecasted amounts and the difference could be material.

For purposes of measuring the fair value of the majority of property, plant and equipment and regulatory assets acquired and regulatory liabilities assumed, KU determined that fair value was equal to net book value at the acquisition date because KU's operations are conducted in a regulated environment and the regulatory commissions allow for earning a rate of return on the book value of a majority of the regulated asset bases at rates determined to be fair and reasonable. As there is no current prospect for deregulation in KU's operating area, it is expected that these operations will remain in a regulated environment for the foreseeable future, therefore management has concluded that the use of these assets in the regulatory environment represents their highest and best use and a market participant would measure the fair value of these assets using the regulatory rate of return as the discount rate, thus resulting in fair value equal to book value.

The fair value of intangible assets and liabilities (e.g. contracts that have favorable or unfavorable terms relative to market), including coal contracts and power purchase agreements, as well as emission allowances, have been reflected on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the acquisition. As a result, management believes the regulatory assets and liabilities created to offset the fair value adjustments meet the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. KU's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU also considered whether a separate fair value should be assigned to KU's rights to operate within its various electric service areas but concluded that these rights only provided the opportunity to earn a regulated return and barriers to market entry, which in management's judgment is not considered a separately identifiable intangible asset under applicable accounting guidance; rather, it is considered going-concern value, or goodwill.

See Note 2, Acquisition by PPL and Note 7, Goodwill and Intangible Assets, for further information.

New Accounting Guidance

Recent accounting pronouncements affecting KU are detailed in Note 1, Summary of Significant Accounting Policies.

Other Information

PPL’s Audit Committee has approved the audit fees and audit-related services. The audit-related services include services in connection with regulatory filings, reviews of offering documents and registration statements and internal control reviews.

Management's Report of Internal Controls Over Financial Reporting

Through December 31, 2010, the Company was not subject to the internal control and other requirements of the Sarbanes-Oxley Act of 2002 and associated rules (the "Act") and consequently is not required to evaluate the effectiveness of its internal control over financial reporting pursuant to Section 404 of the Act. However, management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process affected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework.* Management has concluded that, as of December 31, 2010, the Company's internal control over financial reporting was effective based on those criteria.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included herein.

Kentucky Utilities Company
Statements of Income
(millions)

	Successor	Predecessor		
	November 1 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31 2009	Year Ended December 31 2008
Operating revenues (Note 15)	$ 263	$ 1,248	$ 1,355	$ 1,405
Operating expenses:				
Fuel for electric generation	78	417	434	513
Power purchased (Notes 13 and 15)	28	147	199	221
Other operation and maintenance expenses	66	280	320	275
Depreciation and amortization	26	119	133	136
Total operating expenses	198	963	1,086	1,145
Operating income	65	285	269	260
Equity in earnings of unconsolidated venture (Note 1)	-	3	1	30
Interest expense (Notes 11 and 12)	8	6	6	14
Interest expense to affiliated companies (Notes 11, 12 and 15)	2	62	69	58
Other income (expense) - net	-	(2)	5	8
Income before income taxes	55	218	200	226
Income tax expense (Note 10)	20	78	67	68
Net income	$ 35	$ 140	$ 133	$ 158

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Retained Earnings
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Balance at beginning of period	$ 1,418	$ 1,328	$ 1,195	$ 1,037
Effect of PPL acquisition	(1,418)	-	-	-
Balance at November 1, 2010	-	1,328	1,195	1,037
Net income	35	140	133	158
Cash dividends declared (Note 15)	-	(50)	-	-
Balance at end of period	$ 35	$ 1,418	$ 1,328	$ 1,195

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Comprehensive Income
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Net income	$ 35	$ 140	$ 133	$ 158
Equity investee's other comprehensive loss, net of tax expense of $0, $1, $0 and $0, respectively (Note 1)	-	(2)	-	-
Comprehensive income	$ 35	$ 138	$ 133	$ 158

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets
(millions)

Assets	Successor December 31, 2010	Predecessor December 31, 2009
Current assets:		
Cash and cash equivalents	$ 3	$ 2
Accounts receivable (less allowance for doubtful accounts: 2010, $6; 2009, $3):		
Customer	90	79
Affiliated companies	12	9
Other	20	18
Unbilled revenues	89	76
Fuel, materials and supplies:		
Fuel (predominantly coal)	95	98
Other materials and supplies	41	39
Other intangible assets	22	-
Regulatory assets (Note 3)	9	32
Prepayments and other current assets	15	13
Total current assets	396	366
Investment in unconsolidated venture (Note 1)	30	12
Property, plant and equipment:		
Regulated utility plant – electric	3,630	4,892
Accumulated depreciation	(14)	(1,838)
Net regulated utility plant	3,616	3,054
Construction work in progress	955	1,257
Property, plant and equipment – net	4,571	4,311
Deferred debits and other assets:		
Regulatory assets (Notes 3 and 9):		
Pension benefits	117	105
Other regulatory assets	105	117
Goodwill (Notes 2 and 7)	607	-
Other intangibles assets (Notes 2 and 7)	175	-
Cash surrender value of key man life insurance	39	38
Other assets	19	7
Total deferred debits and other assets	1,062	267
Total assets	$ 6,059	$ 4,956

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (continued)
(millions)

Liabilities and Equity	Successor December 31, 2010	Predecessor December 31, 2009
Current liabilities:		
Current portion of long-term debt (Note 11)	$ -	$ 228
Current portion of long-term debt to affiliated company (Notes 11 and 15)	-	33
Notes payable to affiliated companies (Notes 12 and 15)	10	45
Accounts payable	67	107
Accounts payable to affiliated companies (Note 15)	45	88
Accrued taxes	25	14
Customer deposits	23	22
Regulatory liabilities (Note 3)	41	4
Accrued interest	8	1
Employee accruals	15	13
Other current liabilities	18	14
Total current liabilities	252	569
Long-term debt:		
Long-term bonds (Note 11)	1,841	123
Long-term debt to affiliated company (Notes 11 and 15)	-	1,298
Total long-term debt	1,841	1,421
Deferred credits and other liabilities:		
Deferred income taxes (Note 10)	376	336
Accumulated provision for pensions (Note 9)	113	160
Investment tax credits (Note 10)	104	104
Asset retirement obligations (Notes 3 and 4)	54	34
Regulatory liabilities (Note 3):		
Accumulated cost of removal of utility plant	348	335
Other regulatory liabilities	186	25
Other liabilities	94	20
Total deferred credits and other liabilities	$ 1,275	$ 1,014

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (continued)
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Equity:		
Common stock, without par value – authorized 80,000,000 shares, outstanding 37,817,878 shares	$ 308	$ 308
Additional paid-in capital	2,348	316
Retained earnings:		
Retained earnings	35	1,318
Undistributed earnings from unconsolidated venture	-	10
Total equity	2,691	1,952
Total liabilities and equity	$ 6,059	$ 4,956

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Cash flows from operating activities:				
Net income	$ 35	$ 140	$ 133	$ 158
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Depreciation and amortization	26	119	133	136
Deferred income taxes – net	4	23	50	(13)
Investment tax credits (Note 10)	-	-	24	25
Provision for pension and postretirement benefits	5	13	26	10
Other – net	2	(3)	-	1
Change in current assets and liabilities:				
Accounts receivable	(15)	13	11	13
Unbilled revenues	(32)	19	(15)	(1)
Fuel, materials and supplies	5	(6)	(28)	(33)
Regulatory assets	(2)	19	-	-
Other current assets	9	(9)	(3)	(1)
Accounts payable	9	(17)	(32)	2
Accounts payable to affiliated companies	(41)	46	29	7
Accrued taxes	15	(5)	6	8
Regulatory liabilities	12	3	-	-
Other current liabilities	(2)	2	2	(3)
Pension and postretirement funding (Note 9)	(2)	(18)	(20)	(5)
Storm restoration regulatory asset (Note 3)	-	-	(57)	(2)
Other regulatory assets	1	8	-	-
Other regulatory liabilities	-	(10)	-	-
Other – net	(1)	7	(6)	(10)
Net cash provided by (used in) operating activities	28	344	253	292
Cash flows from investing activities:				
Construction expenditures	(87)	(292)	(516)	(686)
Purchases of assets from affiliate	-	(48)	-	(10)
Change in restricted cash	-	-	9	1
Net cash provided by (used in) investing activities	$ (87)	$ (340)	$ (507)	$ (695)

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows (continued)
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010,	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Cash flows from financing activities:				
Issuance of bonds (Note 11)	$ 1,489	$ -	$ -	$ 77
Short-term borrowings from affiliated company – net (Note 12)	(83)	48	29	(7)
Other borrowings from affiliated companies (Note 11)	1,331	-	150	250
Repayments on other borrowings from affiliated companies (Note 11)	(1,331)	-	-	-
Repayments to E.ON affiliate (Note 11)	(1,331)	-	-	-
Debt issuance costs	(17)	-	-	-
Retirement of pollution control bonds	-	-	-	(60)
Acquisition of outstanding bonds	-	-	-	(80)
Reissuance of reacquired bonds	-	-	-	63
Retirement of reacquired bonds	-	-	-	17
Payment of dividends	-	(50)	-	-
Capital contribution (Note 15)	-	-	75	145
Net cash provided by (used in) financing activities	58	(2)	254	405
Change in cash and cash equivalents	(1)	2	-	2
Cash and cash equivalents at beginning of period	4	2	2	-
Cash and cash equivalents at end of period	$ 3	$ 4	$ 2	$ 2
Supplemental disclosures of cash flow information:				
Cash paid (received) during the year for:				
Interest – net of amount capitalized	$ 22	$ 62	$ 70	$ 66
Income taxes – net	(12)	74	(9)	46

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Long-term debt (Note 11):		
Pollution control series:		
Mercer Co. 2000 Series A, due May 1, 2023, variable %................	$ 13	$ 13
Carroll Co. 2007 Series A, due February 1, 2026, 5.75%................	18	18
Carroll Co. 2002 Series A, due February 1, 2032, variable %.........	21	21
Carroll Co. 2002 Series B, due February 1, 2032, variable %.........	2	2
Muhlenberg Co. 2002 Series A, due February 1, 2032, variable %.	2	2
Mercer Co. 2002 Series A, due February 1, 2032, variable %.........	8	8
Carroll Co. 2008 Series A, due February 1, 2032, variable %.........	78	78
Carroll Co. 2002 Series C, due October 1, 2032, variable %...........	96	96
Carroll Co. 2006 Series B, due October 1, 2034, variable %...........	54	54
Trimble Co. 2007 Series A, due March 1, 2037, 6.0%....................	9	9
Carroll Co. 2004 Series A, due October 1, 2034, variable %	50	50
Total pollution control series...	351	351
First mortgage bonds:		
First mortgage bond 2015 Series, due November 1, 2015, 1.625%	250	-
First mortgage bond 2020 Series, due November 1, 2020, 3.25%	500	-
First mortgage bond 2040 Series, due November 1, 2040, 5.125%	750	-
Total first mortgage bonds...	$ 1,500	$ -

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization (continued)
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Long-term debt to affiliated company:		
Due November 24, 2010, 4.24%, unsecured	$ -	$ 33
Due January 16, 2012, 4.39%, unsecured	-	50
Due April 30, 2013, 4.55%, unsecured	-	100
Due August 15, 2013, 5.31%, unsecured	-	75
Due December 19, 2014, 5.45%, unsecured	-	100
Due July 8, 2015, 4.735%, unsecured	-	50
Due December 21, 2015, 5.36%, unsecured	-	75
Due October 25, 2016, 5.675%, unsecured	-	50
Due April 24, 2017, 5.28%, unsecured	-	50
Due June 20, 2017, 5.98%, unsecured	-	50
Due July 25, 2018, 6.16%, unsecured	-	50
Due August 27, 2018, 5.645%, unsecured	-	50
Due December 17, 2018, 7.035%, unsecured	-	75
Due July 29, 2019, 4.81%, unsecured	-	50
Due October 25, 2019, 5.71%, unsecured	-	70
Due November 25, 2019, 4.445%, unsecured	-	50
Due February 7, 2022, 5.69%, unsecured	-	53
Due May 22, 2023, 5.85%, unsecured	-	75
Due September 14, 2028, 5.96%, unsecured	-	100
Due June 23, 2036, 6.33%, unsecured	-	50
Due March 30, 2037, 5.86%, unsecured	-	75
Total long-term debt to affiliated company	-	1,331
Total long-term debt outstanding	1,851	1,682
Purchase accounting adjustments and discounts	(10)	-
Less current portion of long-term debt	-	261
Long-term debt	$ 1,841	$ 1,421

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization (continued)
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Common equity:		
Common stock, without par value – authorized 80,000,000 shares, outstanding 37,817,878 shares	$ 308	$ 308
Additional paid-in-capital	2,348	316
Retained earnings:		
Retained earnings	35	1,318
Undistributed subsidiary earnings	-	10
Total retained earnings	35	1,328
Total common equity	2,691	1,952
Total capitalization	$ 4,532	$ 3,373

The accompanying notes are an integral part of these financial statements.

Note 1 - Summary of Significant Accounting Policies

General

Terms and abbreviations are explained in the index of abbreviations. Dollars are in millions unless otherwise noted.

Business

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 514,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in five counties in southwestern Virginia and less than ten customers in Tennessee. KU's service area covers approximately 6,600 noncontiguous square miles. Approximately 98% of the electricity generated by KU is produced by its coal-fired electric generating stations. The remainder is generated by natural gas and oil fueled CTs and a hydroelectric power plant. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

On November 1, 2010, KU became an indirect wholly owned subsidiary of PPL, when PPL acquired all of the outstanding limited liability company interests in the Company's direct parent, LKE, from E.ON US Investments Corp. LKE, a Kentucky limited liability company, also owns the affiliate, LG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy and distribution and sale of natural gas in Kentucky. Following the acquisition, the Company's business has not changed. KU and LG&E are continuing as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies.

Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K.

Basis of Accounting

KU's basis of accounting incorporates the business combinations guidance of the FASB ASC as of the date of the acquisition, which requires the recognition and measurement of identifiable assets acquired and liabilities assumed at fair value as of the acquisition date. KU's financial statements and accompanying footnotes have been segregated to present pre-acquisition activity as the Predecessor and post-acquisition activity as the Successor. Predecessor covers the time period prior to November 1, 2010. Successor covers the time period after October 31, 2010. Certain accounting and presentation methods were changed to acceptable alternatives to conform to PPL accounting policies, which are discussed below, and the cost basis of certain assets and liabilities were changed as of November 1, 2010, as a result of the application of push-down accounting. Consequently, the financial position, results of operations and cash flows for the Predecessor period are not comparable to the Successor period.

Despite the separate presentation, the core operations of the Company have not changed. See Note 2, Acquisition by PPL, for information regarding the acquisition and the purchase accounting adjustments.

Changes in Classification

Certain reclassification entries have been made to the Predecessor's previous years' financial statements to conform to the 2010 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows. These reclassifications mainly consist of those necessary to identify amounts for prior periods that are separately disclosed in the financial statements.

Regulatory Accounting

KU is a cost-based rate-regulated utility. As a result, the financial statements reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise be charged to expense. Likewise, regulatory liabilities may be recognized for obligations expected to be returned through future regulated customer rates. The effect of such transactions or events would otherwise be reflected as income, or, in certain cases, regulatory liabilities are recorded based on the understanding with the regulator that current rates are being set to recover costs that are expected to be incurred in the future. The regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. Offsetting regulatory assets or liabilities for fair value purchase accounting adjustments have also been recorded to eliminate any ratemaking impact of the fair value adjustments. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC, Kentucky Commission, Virginia Commission or the Tennessee Regulatory Authority. See Note 3, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Management's Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported assets and liabilities, the disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Derivative Financial Instruments

KU enters into energy trading contracts to manage price risk and to maximize the value of power sales from the physical assets it owns. The energy trading contracts are non-hedging derivatives and the change in value is recognized in earnings on a mark-to-market basis. The Predecessor and Successor presentation are both appropriate under GAAP. The Predecessor and Successor determine the classification of energy trading contracts based on the settlement date of the individual contracts. Energy trading contracts classified as current are recognized in "Prepayments and other current assets" or "Other current liabilities" on the Balance Sheets. Energy trading contracts classified as non-current are recognized in "Other assets" or "Other liabilities" on the Balance Sheets. Cash inflows and outflows

related to derivative instruments are included as a component of operating activity on the Statements of Cash Flows, due to the underlying nature of the hedged items.

The Company does not net collateral against derivative instruments.

See Note 5, Derivative Financial Instruments, and Note 6, Fair Value Measurements, for further information on derivative instruments.

Revenue and Accounts Receivable

The operating revenues line item in the Statements of Income contains revenues from the following:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Residential	$ 106	$ 440	$ 480	$ 462
Industrial and commercial	117	588	637	636
Municipals	15	88	91	92
Other retail	20	114	118	108
Wholesale	5	18	29	107
	$ 263	$ 1,248	$ 1,355	$ 1,405

Revenue Recognition

Revenues are recorded based on service rendered to customers through month-end. Operating revenues are recorded based on energy deliveries through the end of the calendar month. Unbilled retail revenues result because customers' meters are read and bills are rendered throughout the month, rather than all being read at the end of the month. Unbilled revenues for a month are calculated by multiplying an estimate of unbilled kWh by the estimated average cents per kWh.

Accounts Receivable

Accounts receivable are reported in the Balance Sheets at the gross outstanding amount adjusted for an allowance for doubtful accounts.

Allowance for Doubtful Accounts

The allowance for doubtful accounts included in "Accounts receivable – customer" is based on the ratio of the amounts charged-off during the last twelve months to the retail revenues billed over the same period, multiplied by the retail revenues billed over the last four months. Accounts with no payment activity are charged-off after four months, although collection efforts continue thereafter. The allowance for doubtful accounts included in "Accounts receivable – other" is composed of accounts aged more than four months. Accounts are written off as management determines them uncollectible.

The changes in the allowance for doubtful accounts were:

	Successor	Predecessor		
	December 31, 2010	October 31, 2010	December 31, 2009	December 31, 2008
Balance at beginning of period (a)	$ -	$ 3	$ 3	$ 2
Charged to income	1	(6)	(4)	(2)
Charged to balance sheets	5	6	4	3
Balance at end of period	$ 6	$ 3	$ 3	$ 3

(a) Successor beginning of period reflects revaluation of accounts receivable due to purchase accounting.

Cash

Cash Equivalents

All highly liquid investments with an original maturity of three months or less are considered to be cash equivalents.

Restricted Cash

Bank deposits and other cash equivalents that are restricted by agreement or that have been clearly designated for a specific purpose are classified as restricted cash. The change in restricted cash is reported as an investing activity on the Statements of Cash Flows. On the Balance Sheets, restricted cash is included in “Prepayments and other current assets”. For KU, the December 31, 2010, balance of restricted cash was less than $1 million.

Fair Value Measurements

KU values certain financial assets and liabilities at fair value. Generally, the most significant fair value measurements relate to derivative assets and liabilities, investments in securities including investments in the pension and postretirement benefit plans and cash and cash equivalents. KU uses, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques) and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions that market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

KU prioritizes fair value measurements for disclosure by grouping them into one of three levels in the fair value hierarchy. The highest priority is given to measurements using level 1 inputs. The appropriate level assigned to a fair value measurement is based on the lowest level input that is significant to the fair value measurement in its entirety. The three levels of the fair value hierarchy are as follows:

- Level 1 - Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - Other inputs that are directly or indirectly observable in the marketplace.
- Level 3 - Unobservable inputs which are supported by little or no market activity.

Assessing the significance of a particular input requires judgment that considers factors specific to the asset or liability. As such, KU's assessment of the significance of a particular input may affect how the assets and liabilities are classified within the fair value hierarchy. See Note 5, Derivatives Financial Instruments, and Note 6, Fair Value Measurements, for further information on fair value measurements.

Investments

Equity Method Investment

KU's equity method investment, included in "Investment in unconsolidated venture" on the Balance Sheets, consists of its investment in EEI. KU owns 20% of the common stock of EEI, which owns and operates a 1,002 Mw summer capacity coal-fired plant and a 74 Mw summer capacity natural gas facility in southern Illinois. Through a power marketer affiliated with its majority owner, EEI sells its output to third parties. Although KU holds investment interest in EEI, it is not the primary beneficiary and is therefore not consolidated into the Company's financial statements. KU's investment in EEI is accounted for under the equity method of accounting and as of December 31, 2010 and 2009, totaled $30 million and $12 million, respectively. KU's direct exposure to loss as a result of its involvement with EEI is generally limited to the value of its investment. See Note 2, Acquisition by PPL, for further discussion regarding purchase accounting adjustments recognized for KU's investment in EEI.

The results of operations and financial position of EEI, KU's equity method investment, are summarized below.

Condensed income statement information for the years ended December 31 is as follows:

	2010 (unaudited)	2009	2008
Net sales	$ 343	$ 297	$ 514
Net income	16	10	142
KU's equity in earnings of EEI	3	1	30

Condensed balance sheet information as of December 31 is as follows:

	2010 (unaudited)	2009
Current assets	$ 62	$ 84
Long-lived assets	181	178
Total assets	$ 243	$ 262
Current liabilities	$ 113	$ 166
Long-term liabilities	72	50
Equity	58	46
Total liabilities and equity	$ 243	$ 262

Cost Method Investment

KU's cost method investment, included in "Investments in unconsolidated venture" on the Balance Sheets, consists of the Company's investment in OVEC. KU and 11 other electric utilities are owners of OVEC, which is located in Piketon, Ohio. OVEC owns and operates two coal-fired power plants, Kyger Creek Station in Ohio and Clifty Creek Station in Indiana with combined nameplate generating capacities of 2,390 Mw. OVEC's power is currently supplied to KU and 13 other companies affiliated with the various owners. Pursuant to current contractual agreements, KU owns 2.5% of OVEC's common stock and is contractually entitled to 2.5% of OVEC's output. Based on nameplate generating capacity, this would be approximately 60 Mw.

As of December 31, 2010 and 2009, KU's investment in OVEC totaled less than $1 million. KU is not the primary beneficiary of OVEC; therefore, it is not consolidated into the Company's financial statements and is accounted for under the cost method of accounting. The direct exposure to loss as a result of the Company's involvement with OVEC is generally limited to the value of its investment; however, KU may be conditionally responsible for a pro-rata share of certain OVEC obligations. See Note 2, Acquisition by PPL, and Note 13, Commitments and Contingencies, for further discussion regarding purchase accounting adjustments recognized, and KU's ownership interest and power purchase rights.

Long-Lived and Intangible Assets

Regulated Utility Plant

Regulated utility plant was stated at original cost for the Predecessor and adjusted to the net book value on November 1, 2010, the acquisition date, for the Successor. KU determined that fair value was equal to net book value at the acquisition date since KU's operations are conducted in a regulated environment. Original cost includes payroll-related costs such as taxes, fringe benefits and administrative and general costs. Construction work in progress has been included in the rate base for determining retail customer rates. KU has not recorded significant allowance for funds used during construction in accordance with FERC.

The cost of plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost is charged to the reserve for depreciation. When complete operating units are disposed of,

appropriate adjustments are made to the reserve for depreciation and gains and losses, if any, are recognized.

Capitalized Software Cost

Included in "Property, plant and equipment" on the Balance Sheets are capitalized costs of software projects that were developed or obtained for internal use. These capitalized costs are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Following are capitalized software costs and the accumulated amortization:

Successor		Predecessor	
December 31, 2010		December 31, 2009	
Carrying Amount	Accumulated Amortization (a)	Carrying Amount	Accumulated Amortization
$ 40	$ 1	$ 52	$ 13

(a) The accumulated amortization as of November 1, 2010, was netted against the carrying amount of the software as the fair value was determined to be equal to net book value for property, plant and equipment.

Amortization expense of capitalized software costs was as follows:

Successor	Predecessor		
November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
$ 1	$ 6	$ 6	$ 5

The amortization of capitalized software is included in "Depreciation and amortization" on the Statements of Income.

Depreciation and Amortization

Depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. The amounts provided as a percentage of depreciable plant were approximately:

Year	Percentage
2010	4.1%
2009	2.6%
2008	3.0%

Of the amount provided for depreciation, the following were related to the retirement, removal and disposal costs of long lived assets:

Year	Percentage
2010	0.6%
2009	0.4%
2008	0.5%

Goodwill, Intangible Assets and Asset Impairment

KU performs a quarterly review to determine if an impairment analyses is required for long-lived assets that are subject to depreciation or amortization. This review identifies changes in circumstances indicating that a long-lived asset's carrying value may not be recoverable. An impairment analysis will be performed if warranted, based on the review.

For a long-lived asset to be held and used, impairment exists when the carrying amount exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset is impaired, an impairment loss is recorded to adjust the asset's carrying amount to its fair value.

KU, as the result of PPL's acquisition of LKE, recorded the fair value of its coal contracts, emission allowances, EEI investment and OVEC power purchase contract. The difference between the fair value and the cost for these assets is being amortized over their useful lives based upon the pattern in which the economic benefits of the intangible assets are consumed or otherwise used. When determining the useful life of an intangible asset, including intangible assets that are renewed or extended, KU considers the expected use of the asset, the expected useful life of other assets to which the useful life of the intangible asset may relate and legal, regulatory, or contractual provisions that may limit the useful life. See Note 2, Acquisition by PPL, for methods used to determine the long-lived intangible assets' fair values. See Note 7, Goodwill and Intangible Assets, for the fair value amounts and amortization periods. The current intangible assets and long-term intangible assets are included in "Other intangible assets" on the Balance Sheets.

The Predecessor reported emission allowances in "Other materials and supplies" on the Balance Sheets. The emission allowances were not amortized; rather, they were expensed when consumed. The Predecessor did not recognize the coal contracts or the OVEC power purchase contract as these intangible assets were not derivatives.

In connection with PPL's acquisition of LKE, KU recorded goodwill on November 1, 2010. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is tested annually for impairment during the fourth quarter and more frequently if management determines that a triggering event may have occurred that would more likely than not reduce the fair value of an operating unit below its carrying value. Goodwill impairment charges are not subject to rate recovery. See Note 7, Goodwill and Intangible Assets, for further discussion regarding the Company's goodwill and current test results.

Asset Retirement Obligations

KU recognizes various legal obligations associated with the retirement of long-lived assets as liabilities in the financial statements. Initially this obligation is measured at fair value. An equivalent amount is recorded as an increase in the value of the capitalized asset and allocated to expense over the useful life of the asset. Until the obligation is settled, the liability is increased, through the recognition of accretion expense in the Statements of Income, for changes in the obligation due to the passage of time. An offsetting regulatory asset is recognized to reverse the depreciation and accretion expense related to the ARO such that there is no income statement impact. The regulatory asset is relieved when the ARO has been settled. Estimated ARO costs and settlement dates, which affect the carrying value of various AROs and the related assets, are reviewed periodically to ensure that any material changes are incorporated into the latest estimate of the obligations. See Note 4, Asset Retirement Obligations, for further information on AROs.

Defined Benefits

KU employees benefit from both funded and unfunded retirement benefit plans. An asset or liability is recorded to recognize the funded status of all defined benefit plans with an offsetting entry to regulatory assets or regulatory liabilities. Consequently, the funded status of all defined benefit plans is fully recognized on the Balance Sheets.

The expected return on plan assets is determined based on the current level of expected return on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class is then weighted based on the current asset allocation.

The discount rate used for pensions, postretirement and post-employment plans by the Predecessor was determined using the Mercer Yield Curve. The expected return on assets assumption was 7.75%. Gains and losses in excess of 10% of the greater of the plan's projected benefit obligation or market value of assets were amortized on a straight-line basis over the average future service period of active participants. The market-related value of assets was equal to the fair market value of the assets.

The discount rate used by the Successor was determined by the Towers Watson Yield Curve based on the individual plan cash flows. The expected return on assets was reduced from 7.75% to 7.25%. The amortization period for the recognition of gains and losses for retirement plans was changed to reflect the Successor's amortization policy. Under the Successor's method, gains and losses in excess of 10% but less than 30% of the greater of the plan's projected benefit obligation or market-related value of assets, are amortized on a straight-line basis over the average future service period of active participants. Gains and losses in excess of 30% of the plan's projected benefit obligation or market-related value of assets are amortized on a straight-line basis over a period equal to one-half of the average future service period of active participants. The market-related value of assets for the qualified retirement plans will be equal to a five year smoothed asset value. Gains and losses in excess of the expected return will be phased-in over a five-year period, prospectively from November 1, 2010.

See Note 9, Pension and Other Postretirement Benefit Plans, for further information.

Other

Loss Accruals

Potential losses are accrued when information is available that indicates it is “probable” that a loss has been incurred, given the likelihood of uncertain future events, and the amount of the loss can be reasonably estimated. Accounting guidance defines “probable” as cases in which “the future event or events are likely to occur.” KU continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events.

KU does not record the accrual of contingencies that might result in gains unless recovery is assured.

Income Taxes

For the periods ended on or before October 31, 2010, KU was a subsidiary of E.ON U.S. and was part of E.ON U.S.’s direct parent’s, E.ON US Investments Corp., consolidated U.S. federal income tax return. On November 1, 2010, KU became a part of PPL’s consolidated U.S. federal income tax return.

Significant management judgment is required in developing KU’s provision for income taxes primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and the determination of deferred tax assets, liabilities and valuation allowances.

KU evaluates tax positions following a two-step process. The first step requires an entity to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires an entity to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact the financial statements of KU.

Deferred income taxes reflect the net future tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes, as well as the tax effects of net operating losses and tax credit carryforwards.

KU records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. KU considers the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies in initially recording and subsequently reevaluating the need for valuation allowances. If KU determines that it is able to realize deferred tax assets in the future in excess of recorded net deferred tax assets, adjustments to the valuation allowances increase income by reducing tax expense in the period that such determination is made. Likewise, if KU determines that it is not able to realize all or part of net deferred tax assets in the future, adjustments to the valuation allowances would decrease income by increasing tax expense in the period that such determination is made.

The provision for KU's deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the regulators. The difference in the provision for deferred income taxes for regulated assets and liabilities and the amount that otherwise would be recorded under GAAP is deferred and included on the Balance Sheets in "Regulatory liabilities".

KU defers investment tax credits when the credits are utilized and amortizes the deferred amounts over the average lives of the related assets.

See Note 10, Income Taxes, for further discussion regarding income taxes.

Leases

KU evaluates whether arrangements entered into contain leases for accounting purposes.

Materials and Supplies

Fuel and other materials and supplies inventories are accounted for using the average-cost method.

Fuel Costs

The cost of fuel for electric generation is charged to expense as used. See Note 3, Rates and Regulatory Matters, for a description of the FAC.

Debt

The Company's long-term debt includes $228 million of pollution control bonds, which are subject to tender for purchase at the option of the holder and to mandatory tender for purchase on the occurrence of certain events. The Successor has classified these bonds as long term because the Company has the intent and ability to utilize its $400 million credit facility, which matures in December 2014, to fund any mandatory purchases. Predecessor classified these bonds as current portion of long-term debt due to the tender for purchase provisions. The Predecessor presentation and the Successor presentation are both appropriate under GAAP. See Note 11, Long-Term Debt, and Note 12, Notes Payable and Other Short-Term Obligations, for more information on the Company's debt and credit facilities.

Unamortized Debt Expense

Debt expense is capitalized and amortized over the lives of the related bond issues using the straight line method, which approximates the effective interest method. Depending on the type of expense, the Successor capitalized debt expenses in long-term other regulatory assets or long-term other assets to align with the term of the debt the expenses were related. The Predecessor capitalized debt expenses in current or long-term other regulatory assets or other current or long-term other assets based on the amount of expense expected to be recovered within the next year through rate recovery. Both the Predecessor and the Successor amortize debt expenses over the lives of the related bond issues. The Predecessor presentation and the Successor presentation are both appropriate under regulatory practices and GAAP.

Recent Accounting Pronouncements

The following recent accounting pronouncement affected KU:

Fair Value Measurements

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances and settlements within level 3 measurements. This guidance is effective for the interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about the roll-forward of activity in level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. This guidance has no impact on the Company's results of operations, financial position, liquidity or disclosures.

Note 2 - Acquisition by PPL

On November 1, 2010, PPL completed its acquisition of LKE and its subsidiaries. The push-down basis of accounting was used to record the fair value adjustments of assets and liabilities on LKE at the acquisition date. PPL paid a cash consideration for LKE and its subsidiaries of $2,493 million as well as a capital contribution on November 1, 2010, of $1,565 million; included within this was the consideration paid for KU of $2,656 million. The allocation of the KU purchase price was based on the fair value of assets acquired and liabilities assumed.

The allocation of the purchase price to the fair value of assets acquired and liabilities assumed is as follows:

Current assets	$	364
Investments		30
Property, plant and equipment		4,531
Other intangible assets		178
Regulatory and other non-current assets		274
Current liabilities (excluding current portion of long-term debt)		(367)
Affiliated debt		(1,331)
Debt (current and non-current)		(352)
Other non-current liabilities		(1,278)
Net identifiable assets acquired		2,049
Goodwill		607
Total purchase price	$	2,656

Goodwill represents value paid for the rate regulated business of KU, which is located in a defined service area with a constructive regulatory environment, which provides for future investment, earnings and cash flow growth, as well as the talented and experienced workforce. KU's franchise values are being attributed to the going concern value of the business, and thus were recorded as goodwill rather than a separately identifiable intangible asset. None of the goodwill recognized is deductible for income tax purposes or included in regulated customer rates.

Adjustments to KU's assets and liabilities that contributed to goodwill were as follows:

The fair value adjustment on the EEI investment was calculated using the discounted cash flow valuation method. The result was an increase in KU's value of the investment in EEI; the fair value of EEI was calculated to be $30 million and a fair value adjustment of $18 million was recorded on KU. The fair value adjustment to EEI is amortized over the expected remaining useful life of plant and equipment at EEI, which is estimated to be over 20 years.

The pollution control bonds on KU had a fair value adjustment of $1 million. All variable bonds were valued at par while the fixed rate bonds were valued with a yield curve based on average credit spreads for similar bonds.

As a result of the purchase accounting associated with the acquisition, the following items had a fair value adjustment but no effect on goodwill as the offset was either a regulatory asset or liability. The regulatory asset or liability has been recorded to eliminate any ratemaking impact of the fair value adjustments:

- The value of OVEC was determined to be $39 million based upon an announced transaction by another owner. KU's stock was valued at less than $1 million and the power purchase agreement has been valued at $39 million. An intangible asset was recorded with the offset to regulatory liability and will be amortized using the units of production method until the power purchase agreement ends in March 2026.
- KU recorded an emission allowance intangible asset and regulatory liability as the result of adjusting the fair value of the emission allowances at KU. The emission allowance intangible of $9 million represents allocated and purchased SO_2 and NOx emission allowances that are unused as of the valuation date or allocated for use in future years. KU had previously recorded emission allowances as other materials and supplies. To conform to PPL's accounting policy all emission allowances are now recorded as intangible assets. The emission allowance intangible asset is amortized as the emission allowances are consumed, which is expected to occur through 2040.
- KU recorded a coal contract intangible asset of $145 million and non-current liability of $22 million on the Balance Sheets. An offsetting regulatory asset was recorded for those contracts with unfavorable terms relative to market. An offsetting regulatory liability was recorded for those contracts that had favorable terms relative to market. All coal contracts held by KU, wherein it had entered into arrangements to buy amounts of coal at fixed prices from counterparties at a future date, were fair valued. The intangible assets and other liabilities, as well as the regulatory assets and liabilities, are being amortized over the same terms as the related contracts, which expire through 2016.

The fair value of intangible assets and liabilities (e.g. contracts that have favorable or unfavorable terms relative to market), including coal contracts and power purchase agreements, as well as emission allowances, have been reflected on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the acquisition. As a result, management believes the regulatory assets and liabilities created to offset the fair value adjustments meet the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair

value adjustments. KU's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU also considered whether a separate fair value should be assigned to KU's rights to operate within its various electric service areas but concluded that these rights only provided the opportunity to earn a regulated return and barriers to market entry, which in management's judgment is not considered a separately identifiable intangible asset under applicable accounting guidance; rather, it is considered going-concern value, or goodwill.

Note 3 - Rates and Regulatory Matters

The Company is subject to the jurisdiction of the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority in virtually all matters related to electric utility regulation and as such, its accounting is subject to the regulated operations guidance of the FASB ASC. Given its position in the marketplace and the status of regulation in Kentucky and Virginia, there are no plans or intentions to discontinue the application of the regulated operations guidance of the FASB ASC.

KU's Kentucky base rates are calculated based on a return on capitalization (common equity, long-term debt and notes payable) including certain regulatory adjustments to exclude non-regulated investments and environmental compliance plans recovered separately through the ECR mechanism. No regulatory assets or regulatory liabilities recorded at the time base rates were determined were excluded from the return on capitalization utilized in the calculation of Kentucky base rates. Therefore, a return is earned on all Kentucky regulatory assets existing at the time base rates were determined, except where such regulatory assets were offset by associated liabilities and thus, have no net impact on capitalization.

As a result of purchase accounting, certain fair value amounts, reflecting contracts that have favorable or unfavorable terms relative to market, were recorded on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered in customer rates the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. KU's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU's Virginia base rates are calculated based on a return on rate base. All regulatory assets and liabilities are excluded from the return on rate base utilized in the calculation of Virginia base rates.

KU's wholesale requirements rates for municipal customers are calculated based on annual updates to a rate formula that utilizes a return on rate base. All regulatory assets and liabilities are excluded from the return on rate base utilized in the development of municipal rates.

<u>2010 Purchase and Sale Agreement with PPL</u>

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments Corp., PPL and E.ON.

The transaction was subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals

(including the FERC and state regulators in Kentucky, Virginia and Tennessee) and the absence of injunctions or restraints imposed by governmental entities.

Change of control and financing-related applications were filed on May 28, 2010 with the Kentucky Commission and on June 15, 2010 with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings and data request filings and responses occurred. Early termination of the Hart-Scott-Rodino waiting period was received on August 2, 2010.

A hearing in the Kentucky Commission proceedings was held on September 8, 2010 at which time a unanimous settlement agreement was presented. In the settlement, KU committed that no base rate increases would take effect before January 1, 2013. The KU rate increases that took effect on August 1, 2010, were not impacted by the settlement. Under the terms of the settlement, KU retains the right to seek approval for the deferral of "extraordinary and uncontrollable costs." Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and demand-side management cost trackers. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Utilities file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits KU to earn up to a 10.75% return on equity. Any earnings above a 10.75% return on equity will be shared with customers on a 50%/50% basis. On September 30, 2010, the Kentucky Commission issued an Order approving the transfer of ownership of KU via the acquisition of E.ON U.S. by PPL, incorporating the terms of the submitted settlement. On October 19, 2010 and October 21, 2010, respectively, Orders approving the acquisition of E.ON U.S. by PPL were received from the Virginia Commission and the Tennessee Regulatory Authority. The Commissions' Orders contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In mid-September 2010, KU and other applicants in the FERC change of control proceeding reached an agreement with the protesters, whereby such protests have been withdrawn. The agreement, which was filed for consideration with the FERC, includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an agreement not to terminate certain KU municipal customer contracts prior to January 2017, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that KU has agreed not to seek the same transaction-related costs from retail customers and agreements to coordinate with protesters in certain open or ongoing matters. A FERC Order approving the transaction was received on October 26, 2010 and the transaction was completed November 1, 2010.

2010 Kentucky Rate Case

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $135 million annually. In June 2010, KU and all of the intervenors, except the AG, agreed to stipulations providing for an increase in electric base rates of $98 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulations, including a return on equity range of 9.75 – 10.75%. The new rates became effective on August 1, 2010.

Virginia Rate Case

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based on a return on equity of 12%. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing base rate revenue increases of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU refunded $1 million in interim rate amounts in excess of the ultimate approved rates.

FERC Wholesale Rate Case

In September 2008, KU filed an application with the FERC for increases in electric base rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from an all-in stated unit charge rate to an unbundled formula rate, including an annual adjustment mechanism. In 2009, the FERC issued an Order approving a settlement among the parties in the case, incorporating increases of approximately 3% from prior rates and a return on equity of 11%. In May 2010, KU submitted to the FERC the proposed current annual adjustments to the formula rates which incorporated certain proposed increases. Updated rates, including certain further adjustments from a review process involving wholesale requirements customers, became effective as of July 1, 2010, subject to certain review procedures by the wholesale requirements customers and the FERC.

By mutual agreement, the parties' settlement of the 2008 application left outstanding the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. An Order was issued by the FERC in July 2010, indicating that KU is not required to allocate a portion of any renewable resources to the twelve municipalities, thus resolving the remaining issue.

2008 Kentucky Rate Case

In July 2008, KU filed an application with the Kentucky Commission requesting an increase in electric base rates. In January 2009, KU, the AG, the KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which KU's electric base rates decreased by $9 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in the Balance Sheets as of December 31:

	Successor 2010	Predecessor 2009
Current regulatory assets:		
ECR (a)	$ -	$ 28
FAC (a)	-	1
Coal contracts (b)	4	-
MISO exit (c)	-	2
Other (d)	5	1
Total current regulatory assets	$ 9	$ 32
Non-current regulatory assets:		
Pension and postretirement benefits (e)	$ 117	$ 105
Other non-current regulatory assets:		
Storm restoration (c)	57	59
ARO (f)	2	30
Unamortized loss on bonds (c)	12	12
Coal contracts (b)	14	-
MISO exit (a)	5	9
Unamortized debt expense	5	-
Other (d)	10	7
Subtotal other non-current regulatory assets	105	117
Total non-current regulatory assets	$ 222	$ 222
Current regulatory liabilities:		
Coal contracts	$ 16	$ -
ECR	12	-
FAC	2	-
DSM	5	3
Emission allowances	6	-
Other (g)	-	1
Total current regulatory liabilities	$ 41	$ 4
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$ 348	$ 335
Other non-current regulatory liabilities:		
Coal contracts	126	-
OVEC power purchase contract	38	-
Deferred income taxes – net	6	9
Postretirement benefits	10	9
Other (g)	6	7
Subtotal other non-current regulatory liabilities	186	25
Total non-current regulatory liabilities	$ 534	$ 360

(a) The FAC and ECR regulatory assets have separate recovery mechanisms with recovery within twelve months.
(b) Offsetting regulatory asset for fair value purchase accounting adjustments. See Note 2, Acquisition by PPL, for information on the purchase accounting adjustments.
(c) These regulatory assets are recovered through base rates.
(d) Other regulatory assets include:
   - The CMRG and KCCS contributions, an EKPC FERC transmission settlement agreement and rate case expenses, which are recovered through base rates.
   - The FERC jurisdictional portion of the EKPC FERC transmission settlement agreement included in current and non-current regulatory assets, recovered through the application of the annual OATT formula rate updates.
   - FERC jurisdictional pension expense, which will be requested in a future FERC rate case.
   - Offsetting regulatory asset for fair value purchase accounting adjustment for leases. See Note 2, Acquisition by PPL, for information on the purchase accounting adjustments.
   - The Virginia levelized fuel factor, which is a separate recovery mechanism with recovery within twelve months.
(e) KU generally recovers this asset through pension expense included in the calculation of base rates.
(f) When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability.
(g) Other regulatory liabilities includes the emission allowance purchase accounting offset, MISO exit and a change in accounting method for FERC jurisdictional spare parts.

ECR

KU recovers the costs of complying with the Federal Clean Air Act pursuant to Kentucky Revised Statute 278-183 as amended and those federal, state or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal, through the ECR mechanism. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

The Kentucky Commission requires reviews of the past operations of the environmental surcharge for six-month and two-year billing periods to evaluate the related charges, credits and rates of return, as well as to provide for the roll-in of ECR amounts to base rates each two-year period. In December 2010, the Kentucky Commission initiated a six-month review of the Utilities' environmental surcharge for the billing period ending October 2010. An order is expected in the second quarter of 2011. Also, in December 2010, an Order was issued approving the charges and credits billed through the ECR during the six-month period ending April 2010, as well as approving billing adjustments for under-recovered costs and the rate of return on capital. In May 2010, an Order was issued approving the amounts billed through the ECR during the six-month period ending October 2009, and the rate of return on capital and allowing recovery of the under-recovery position in subsequent monthly filings. In December 2009, an Order was issued approving the charges and credits billed through the ECR during the two-year period ending April 2009, an increase in the jurisdictional revenue requirement, a base rate roll-in and a revised rate of return on capital. In July 2009, an Order was issued approving the charges and credits billed through the ECR during the six-month period ending October 2008, as well as approving billing adjustments for under-recovered costs and the rate of return on capital. In August 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month periods ending April

2008 and October 2007, and the rate of return on capital. In March 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month and two-year periods ending October 2006 and April 2007, respectively, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. During 2009, KU reached a unanimous settlement with all parties to the case and the Kentucky Commission issued an Order approving KU's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle. At December 31, 2009, the Company had a regulatory asset of $28 million, which changed to a regulatory liability in the first quarter of 2010, as a result of these roll-in adjustments to base rates. At December 31, 2010, the regulatory liability balance was $12 million.

In February 2009, the Kentucky Commission approved a settlement agreement in the rate case which provides for an authorized return on equity applicable to the ECR mechanism of 10.63% effective with the February 2009 expense month filing, which represents a slight increase over the previously authorized 10.50%. The 10.63% return on equity for the ECR mechanism was affirmed in the 2010 rate case.

FAC

KU's retail rates contain an FAC, whereby increases and decreases in the cost of fuel for generation are reflected in the rates charged to retail customers. The FAC allows the Company to adjust billed amounts for the difference between the fuel cost component of base rates and the actual fuel cost, including transportation costs. Refunds to customers occur if the actual costs are below the embedded cost component. Additional charges to customers occur if the actual costs exceed the embedded cost component. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

The Kentucky Commission requires public hearings at six-month intervals to examine past fuel adjustments and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges. In December 2010, May 2010, November 2009, January 2009, June 2008 and January 2008, the Kentucky Commission issued Orders approving the charges and credits billed through the FAC for the six-month periods ending April 2010, August 2009, April 2009, April 2008, October 2007 and April 2007, respectively. In January 2009 the Kentucky Commission initiated routine examinations of the FAC for the two-year periods November 1, 2006 through October 31, 2008. The Kentucky Commission issued an Order in June 2009 approving the charges and credits billed through the FAC during the review periods.

KU also employs an FAC mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The Virginia levelized fuel factor allows fuel recovery based on projected fuel costs for the coming year plus an adjustment for any over- or under-recovery of fuel expenses from the prior year. At December 31, 2010 and 2009, KU had a regulatory asset of $5 million and less than $1 million, respectively.

In February 2010, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor beginning with service rendered in April 2010. An Order was issued in April 2010, resulting in an agreed upon decrease of 23% from the fuel factor in effect for April 2009 through March 2010.

In February 2009, KU filed an application with the Virginia Commission seeking approval of a 29% increase in its fuel cost factor beginning with service rendered in April 2009. In February 2009, the Virginia Commission issued an Order allowing the requested change to become effective on an interim basis. The Virginia Staff testimony filed in April 2009 recommended a slight decrease in the factor filed by KU. The Company indicated the Virginia Staff proposal was acceptable. A hearing was held in May 2009, with general resolution of remaining issues. In May 2009, the Virginia Commission issued an Order approving the revised fuel factor, representing an increase of 24%, effective May 2009.

In February 2008, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor applicable during the billing period, April 2008 through March 2009. The Virginia Commission allowed the new rates to be in effect for the April 2008 customer billings. In April 2008, the Virginia Commission Staff recommended a change to the fuel factor KU filed in its application, to which KU agreed. Following a public hearing and an Order in May 2008, the recommended change became effective in June 2008, resulting in a decrease of 0.482 cents/kWh from the factor in effect for the April 2007 through March 2008 period.

Coal Contracts

In November 2010, purchase accounting adjustments were recorded for the fair value of KU's coal contracts. Offsetting regulatory asset or liability for fair value purchase accounting adjustments eliminate any ratemaking impact of the fair value adjustments.

MISO

Following receipt of applicable FERC, Kentucky Commission and other regulatory Orders, related to proceedings that had been underway since July 2003, KU withdrew from the MISO effective September 1, 2006. Since the exit from the MISO, KU has been operating under a FERC approved OATT. KU now contracts with the TVA to act as its transmission reliability coordinator and SPP to function as its independent transmission operator, pursuant to FERC requirements. The contractual obligations with the TVA extend through August 2011 and with SPP through August 2012.

KU and the MISO agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, the Company paid $20 million to the MISO and made related FERC compliance filings. The Company's payment of this exit fee was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. KU and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee and the approved agreement providing KU with recovery of $4 million, of which $1 million was immediately recovered in 2008, with the remainder to be recovered over the seven years from 2008 through 2014 for credits realized from other payments the MISO will receive, plus interest.

In accordance with Kentucky Commission Orders approving the MISO exit, KU established a regulatory asset for the MISO exit fee, net of former MISO administrative charges collected via base rates through the base rate case test year ended April 30, 2008. The net MISO exit fee is subject to adjustment for possible future MISO credits and a regulatory liability for certain revenues associated with former MISO administrative charges, which were collected via base rates until February 6, 2009. The approved 2008 base rate case settlement provided for MISO administrative charges collected through base rates from May 1, 2008 to February 6, 2009, and any future adjustments to the MISO exit fee, to be established as a regulatory liability until the amounts can be amortized in future base rate cases. This regulatory liability balance as of October 31, 2009, was included in the base rate case application filed on January 29, 2010. MISO exit fee credit amounts subsequent to October 31, 2009, will continue to accumulate as a regulatory liability until they can be amortized in future base rate cases.

In November 2008, the FERC issued Orders in industry-wide proceedings relating to MISO RSG calculation and resettlement procedures. RSG charges are amounts assessed to various participants active in the MISO trading market which generally seek to compensate for uneconomic generation dispatch due to regional transmission or power market operational considerations, with some customer classes eligible for payments, while others may bear charges. The FERC Orders approved two requests for significantly altered formulas and principles, each of which the FERC applied differently to calculate RSG charges for various historical and future periods. Based upon the 2008 FERC Orders, the Company established a reserve during the fourth quarter of 2008 of less than $1 million relating to potential RSG resettlement costs for the period ended December 31, 2008. However, in May 2009, after a portion of the resettlement payments had been made, the FERC issued an Order on the requests for rehearing on one November 2008 Order which changed the effective date and reduced almost all of the previously accrued RSG resettlement costs. Therefore, these costs were reversed and a receivable was established for amounts already paid of less than $1 million. The MISO began refunding the amounts to the Company in June 2009 with full repayment by September 2009. In June 2009, the FERC issued an Order in the rate mismatch RSG proceeding, stating it will not require resettlements of the rate mismatch calculation from April 1, 2005 to November 4, 2007. An accrual had previously been recorded in 2008 for the rate mismatch issue for the time period April 25, 2006 to August 9, 2007, but no accrual had been recorded for the time period November 5, 2007 to November 9, 2008 based on the prior Order. Accordingly, the accrual for the former time period was reversed and an accrual for the latter time period was recorded in June 2009, with a net effect of $1 million of expense, substantially all of which was paid by September 2009.

In August 2009, the FERC determined that the MISO had failed to demonstrate that its proposed exemptions to real-time RSG charges were just and reasonable. In November 2009, the MISO made a compliance filing incorporating the rulings of the FERC Orders and a related task force, with a primary open issue being whether certain of the tariff changes are applied prospectively only or retroactively to approximately January 6, 2009.

In November 2009, the Utilities filed an application with the FERC to approve certain independent transmission operator arrangements to be effective upon the expiration of their current contract with SPP in September 2010. The application sought authority for KU and LG&E to function after such date as the administrators of their own OATT for most purposes. However, due to the lack of FERC approval for such an approach and the approaching expiration of the SPP contract, the Utilities determined the approach was no longer reasonably achievable without unacceptable delay and uncertainty. In July 2010, the Utilities entered into a new agreement with SPP to provide independent transmission operator

services for a specified, limited time and removed its application for authority of administering its own OATT. The TVA, which currently acts as reliability coordinator, has also been retained under the existing service contract. The new agreement extends TVA services to August 2011 with no alterations or changes to the party's duties or responsibilities.

In August 2010, the FERC issued three Orders accepting most facets of several MISO RSG compliance filings. The FERC ordered the MISO to issue refunds for RSG charges that were imposed by the MISO on the assumption that there were rate mismatches for the period beginning November 5, 2007 through the present. There is no financial statement impact to the Company from this Order, as the MISO had anticipated that the FERC would require these refunds and had preemptively included them in the resettlements paid in 2009. The FERC denied the MISO's proposal to exempt certain resources from RSG charges, effective prospectively. The FERC accepted portions and rejected portions of the MISO's proposed RSG rate Redesign Proposal, which will be effective when the software is ready for implementation subject to further compliance filings. The impact of the Redesign Proposal on the Company cannot be estimated at this time.

Pension and Postretirement Benefits

KU accounts for pension and postretirement benefits in accordance with the compensation – retirement benefits guidance of the FASB ASC. This guidance requires employers to recognize the over-funded or under-funded status of a defined benefit pension and postretirement plan as an asset or liability on the Balance Sheets and to recognize through other comprehensive income the changes in the funded status in the year in which the changes occur. Under the regulated operations guidance of the FASB ASC, KU can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky and Virginia is based on the compensation – retirement benefits guidance of the FASB ASC. Regulators have been clear and consistent with their historical treatment of such rate recovery; therefore, the Company has recorded a regulatory asset representing the change in funded status of its pension plan that is expected to be recovered and a regulatory liability representing the change in funded status of its postretirement benefit plan. The regulatory asset and liability will be adjusted annually as prior service cost and actuarial gains and losses are recognized in net periodic benefit cost.

Storm Restoration

In January 2009, a significant ice storm passed through KU's service area causing approximately 199,000 customer outages, followed closely by a severe wind storm in February 2009, causing approximately 44,000 customer outages. An application was filed with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the establishment of a regulatory asset of up to $62 million based on actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, a regulatory asset of $57 million was established for actual costs incurred and approval was received in KU's 2010 base rate case to recover this asset over a ten year period beginning August 1, 2010.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service area causing significant outages and system damage. In October 2008, an application was filed with the

Kentucky Commission requesting approval to establish regulatory assets and defer for future recovery approximately $3 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the establishment a regulatory asset of up to $3 million based on actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, a regulatory asset of $2 million was established for actual costs incurred and KU received approval in its 2010 base rate case to recover this asset over a ten year period, beginning August 1, 2010.

Unamortized Loss on Bonds

The costs of early extinguishment of debt, including call premiums, legal and other expenses, and any unamortized balance of debt expense are amortized using the straight-line method, which approximates the effective interest method, over the life of either the replacement debt (in the case of refinancing) or the original life of the extinguished debt.

CMRG and KCCS Contributions

In July 2008, KU and LG&E, along with Duke Energy Kentucky, Inc. and Kentucky Power Company, filed an application with the Kentucky Commission requesting approval to establish regulatory assets related to contributions to the CMRG for the development of technologies for reducing carbon dioxide emissions and the KCCS to study the feasibility of geologic storage of carbon dioxide. The filing companies proposed that these contributions be treated as regulatory assets to be deferred until recovery is provided in the next base rate case of each company, at which time the regulatory assets will be amortized over the life of each project: four years with respect to the KCCS and ten years with respect to the CMRG. KU and LG&E jointly agreed to provide $2 million over two years to the KCCS and up to $2 million over ten years to the CMRG. In October 2008, an Order approving the establishment of the requested regulatory assets was received. KU received approval from the Kentucky Commission in the Company’s 2010 Kentucky base rate case to recover these regulatory assets over the requested period beginning August 1, 2010.

Rate Case Expenses

KU incurred $1 million in expenses related to the development and support of the 2008 Kentucky base rate case. The Kentucky Commission approved the establishment of a regulatory asset for these expenses and authorized amortization over three years beginning in March 2009.

KU incurred $2 million in expenses related to the development and support of the 2010 Kentucky base rate case. The Kentucky Commission approved the establishment of a regulatory asset for these expenses and authorized amortization over three years beginning in August 2010.

FERC Jurisdictional Pension Costs

Other regulatory assets include pension costs of $5 million incurred by the Company and allocated to its FERC jurisdictional ratepayers. The Company will seek recovery of this asset in the next FERC rate proceeding.

Deferred Storm Costs

Based on an Order from the Kentucky Commission in June 2004, KU reclassified from maintenance expense to a regulatory asset $4 million related to costs not reimbursed from the 2003 ice storm. These costs were amortized through June 2009. KU earned a return of these amortized costs, which were included in jurisdictional operating expenses.

DSM

DSM consists of energy efficiency programs which are intended to reduce peak demand and delay the investment in additional power plant construction, provide customers with tools and information to become better managers of their energy usage and prepare for potential future legislation governing energy efficiency. KU's rates contain a DSM provision which includes a rate mechanism that provides for concurrent recovery of DSM costs and provides an incentive for implementing DSM programs. The provision allows KU to recover revenues from lost sales associated with the DSM programs based on program plan engineering estimates and post-implementation evaluations.

In July 2007, KU and LG&E filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. KU and LG&E filed revised tariffs in April 2008, under authority of this Order, which were effective in May 2008.

Emission Allowances

In November 2010, purchase accounting adjustments were recorded for the fair market value of KU's SO_2, NOx ozone season and NOx annual emission allowances. Offsetting regulatory assets or liabilities for fair value purchase accounting adjustments eliminate any ratemaking impact of the fair value adjustments. KU is granted SO_2 emission allowances through 2040 and NOx ozone season and NOx annual emission allowances through 2011.

Accumulated Cost of Removal of Utility Plant

As of December 31, 2010 and 2009, KU segregated the cost of removal, previously embedded in accumulated depreciation, of $348 million and $335 million, respectively, in accordance with FERC Order No. 631. For reporting purposes on the Balance Sheets, KU presented this cost of removal as a "Regulatory liability" pursuant to the regulated operations guidance of the FASB ASC.

OVEC Power Purchase Contract

In November 2010, purchase accounting adjustments were recorded for the fair value of the power purchase agreement between KU and OVEC. Offsetting regulatory liability for fair value purchase accounting adjustment eliminate any ratemaking impact of the fair value adjustments.

Deferred Income Taxes – Net

These regulatory liabilities represent the future revenue impact from the reversal of deferred income taxes required for unamortized investment tax credits, the allowance for funds used during construction and deferred taxes provided at rates in excess of currently enacted rates.

Other Regulatory Matters

Kentucky Commission Report on Storms

In November 2009, the Kentucky Commission issued a report following review and analysis of the effects and utility response to the September 2008 wind storm and the January 2009 ice storm and possible utility industry preventative measures relating thereto. The report suggested a number of proposed or recommended preventative or responsive measures, including consideration of selective hardening of facilities, altered vegetation management programs, enhanced customer outage communications and similar measures. In March 2010, the Utilities filed a joint response reporting on their actions with respect to such recommendations. The response indicated implementation or completion of substantially all of the recommendations, including, among other matters, on-going reviews of system hardening and vegetation management procedures, certain test or pilot programs in such areas and fielding of enhanced operational and customer outage-related systems.

Wind Power Agreements

In August 2009, KU and LG&E filed a notice of intent with the Kentucky Commission indicating their intent to file an application for approval of wind power purchase contracts and cost recovery mechanisms. The contracts were executed in August 2009 and were contingent upon KU and LG&E receiving acceptable regulatory approvals. Pursuant to the proposed 20-year contracts, KU and LG&E would jointly purchase respective assigned portions of the output of two Illinois wind farms totaling an aggregate 109.5 Mw. In September 2009, the Utilities filed an application and supporting testimony with the Kentucky Commission. In October 2009, the Kentucky Commission issued an Order denying the Utilities' request to establish a surcharge for recovery of the costs of purchasing wind power. The Kentucky Commission stated that such recovery constitutes a general rate adjustment and is subject to the regulations of a base rate case. The Kentucky Commission Order provided for the request for approval of the wind power agreements to proceed independently from the request to recover the costs thereof via surcharges. In November 2009, KU and LG&E filed for rehearing of the Kentucky Commission's Order and requested that the matters of approval of the contract and recovery of the costs thereof remain the subject of the same proceeding. During December 2009, the Kentucky Commission issued data requests on this matter. In March 2010, the Utilities delivered notices of termination under provisions of the wind power contracts. The Utilities also filed a motion with the Kentucky Commission noting the termination of the contracts and seeking withdrawal of their application in the related regulatory proceeding. In April 2010, the Kentucky Commission issued an Order allowing the Utilities to withdraw their pending application.

Trimble County Asset Purchase and Depreciation

In July 2009, the Utilities notified the Kentucky Commission of the proposed sale from the Utilities of certain ownership interests in certain existing Trimble County generating station assets which were

anticipated to provide joint or common use in support of the jointly-owned TC2 generating unit under construction at the station. The undivided ownership interests sold provide KU an ownership interest in these common assets proportional to its interest in TC2 and the assets' role in supporting both TC1 and TC2. In December 2009, the Utilities completed the sale transaction at a price of $48 million, representing the current net book value of the assets multiplied by the proportional interest being sold.

In August 2009, the Utilities jointly filed an application with the Kentucky Commission to approve new depreciation rates for applicable jointly-owned TC2-related generating, pollution control and other plant equipment and assets. During December 2009, the Kentucky Commission extended the data discovery process through January 2010 and authorized the Utilities on an interim basis to begin using the depreciation rates for TC2 as proposed in the application. In March 2010, the Kentucky Commission issued a final Order approving the use of the proposed depreciation rates on a permanent basis.

TC2 CCN Application and Transmission Matters

An application for a CCN for construction of TC2 was approved by the Kentucky Commission in November 2005. CCNs for two transmission lines associated with TC2 were issued by the Kentucky Commission in September 2005 and May 2006. All regulatory approvals and rights of way for one transmission line have been obtained.

KU's and LG&E's CCN for a transmission line associated with the TC2 construction has been challenged by certain property owners in Hardin County, Kentucky. Certain proceedings relating to CCN challenging and federal historic preservation permit requirements have concluded with outcomes in the Utilities' favor.

Completion of the transmission lines are also subject to standard construction permit, environmental authorization and real property or easement acquisition procedures. Certain Hardin County landowners have raised challenges to the transmission line in some of these forums as well.

With respect to the remaining on-going dispute, KU obtained various successful rulings during 2008 at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals and received a temporary stay preventing KU from accessing their properties. In May 2010, the Kentucky Court of Appeals issued an Order affirming the Hardin Circuit Court's finding that KU had the right to condemn easements on the properties. In May 2010, the landowners filed a petition for reconsideration with the Court of Appeals. In July 2010, the Court of Appeals denied that petition. In August, 2010, the landowners filed for discretionary review of that denial by the Kentucky Supreme Court.

Settlement discussions with the Hardin County property owners involved in the appeals of the condemnation proceedings have been unsuccessful to date. During the fourth quarter of 2008, KU and LG&E entered into settlements with certain Meade County landowners and obtained dismissals of prior litigation they brought challenging the same transmission line.

As a result of the aforementioned unresolved litigation delays encountered in obtaining access to certain properties in Hardin County, KU obtained easements to allow construction of temporary transmission facilities, bypassing those properties while the litigated issues are resolved. In September 2009, the Kentucky Commission issued an Order stating that a CCN was necessary for two segments of the

proposed temporary facilities. In December 2009, the Kentucky Commission granted the CCNs for the relevant segments and the property owners have filed various motions to intervene, stay and appeal certain elements of the Kentucky Commission's recent orders. In January 2010, in respect of two of such proceedings, the Franklin County circuit court issued Orders denying the property owners' request for a stay of construction and upholding the prior Kentucky Commission denial of their intervenor status.

Consistent with the regulatory authorizations and the favorable outcome of the legal proceedings, the Utilities completed construction activities on the permanent transmission line easements. During 2010, the Utilities placed the transmission line into operation. While the Utilities are not currently able to predict the ultimate outcome and possible financial effects of the remaining legal proceedings, the Utilities do not believe the matter involves relevant or continuing risks to operations.

Utility Competition in Virginia

The Commonwealth of Virginia passed the Virginia Electric Utility Restructuring Act in 1999. This act gave customers the ability to choose their electric supplier and capped electric rates through December 2010. KU subsequently received a legislative exemption from the customer choice requirements of this law. In April 2007, however, the Virginia General Assembly amended the Virginia Electric Utility Restructuring Act, thereby terminating this competitive market and commencing re-regulation of utility rates. The new act ended the cap on rates at the end of 2008. Pursuant to this legislation, the Virginia Commission adopted regulations revising the rules governing utility rate increase applications. As of January 2009, a hybrid model of regulation is being applied in Virginia. Under this model, utility rates are reviewed every two years. KU's exemption from the requirements of the Virginia Electric Utility Restructuring Act in 1999, however, discharges the Company from the requirements of the new hybrid model of regulation. In lieu of submitting an annual information filing, the Company has the option of requesting a change in base rates to recover prudently incurred costs by filing a traditional base rate case. KU is also subject to other utility regulations in Virginia, including, but not limited to, the recovery of prudently incurred fuel costs through an annual fuel factor charge and the submission of integrated resource plans.

Market-Based Rate Authority

In July 2006, the FERC issued an Order in KU's market-based rate proceeding accepting the Company's further proposal to address certain market power issues the FERC claimed would arise upon an exit from the MISO. In particular, the Company received permission to sell power at market-based rates at the interface of balancing areas in which it may be deemed to have market power, subject to a restriction that such power will not be collusively re-sold back into such balancing areas. However, restrictions exist on sales by KU of power at market-based rates in the KU and LG&E and Big Rivers Electric Company balancing areas. In June 2007, the FERC issued Order No. 697 implementing certain reforms to market-based rate regulations, including restrictions similar to those previously in place for the Company's power sales at balancing area interfaces. In December 2008, the FERC issued Order No. 697-B potentially placing additional restrictions on certain power sales involving areas where market power is deemed to exist. As a condition of receiving and retaining market-based rate authority, KU must comply with applicable affiliate restrictions set forth in the FERC regulation. During September 2008, the Company submitted a regular triennial update filing under market-based rate regulations.

In June 2009, the FERC issued Order No. 697-C which generally clarified certain interpretations relating to power sales and purchases at balancing area interfaces or into balancing areas involving market power. In July 2009, the FERC issued an Order approving the Company's September 2008 application for market-based rate authority. During July 2009, affiliates of KU completed a transaction terminating certain prior generation and power marketing activities in the Big Rivers Electric Company balancing area, which termination should ultimately allow a filing to request a determination that the Company no longer is deemed to have market power in such balancing area.

KU conducts certain of its wholesale power sales activities in accordance with existing market-based rate authority principles and interpretations. Future FERC proceedings relating to Orders 697 or market-based rate authority could alter the amount of sales made at market-based versus cost-based rates. The Company's sales under market-based rate authority totaled less than $1 million for the year ended December 31, 2010.

Mandatory Reliability Standards

As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007 and authority was delegated to various Regional Reliability Organizations ("RROs") by the NERC, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. The Utilities are members of the SERC, which acts as KU's and LG&E's RRO. During December 2009 and April, July and August 2010, the Utilities submitted ten self-reports relating to various standards, which self-reports remain in the early stages of RRO review, and therefore, the Utilities are unable to estimate the outcome of these matters. Mandatory reliability standard settlements commonly also include non-penalty elements, including compliance steps and mitigation plans. Settlements with SERC proceed to NERC and FERC review before becoming final. While the Utilities believe they are in compliance with the mandatory reliability standards, events of potential non-compliance may be identified from time-to-time. The Utilities cannot predict such potential violations or the outcome of self-reports described above.

Integrated Resource Planning

Integrated resource planning ("IRP") regulations in Kentucky require major utilities to make triennial IRP filings with the Kentucky Commission. In April 2008, KU and LG&E filed their 2008 joint IRP with the Kentucky Commission. The IRP provides historical and projected demand, resource and financial data and other operating performance and system information. The Kentucky Commission issued a staff report and Order closing this proceeding in December 2009. Pursuant to the Virginia Commission's December 2008 Order, KU filed its IRP in July 2009. The filing consisted of the 2008 Joint IRP filed by KU and LG&E with the Kentucky Commission along with additional data. The Virginia Commission has not established a procedural schedule for this proceeding. KU expects to file their next IRP in April 2011.

PUHCA 2005

PPL, KU's ultimate parent, is a holding company under PUHCA 2005. PPL, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries, are subject to extensive regulation by the FERC

with respect to numerous matters, including electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. KU believes that it has adequate authority, including financing authority, under existing FERC Orders and regulations to conduct its business and will seek additional authorization when necessary.

EPAct 2005

The EPAct 2005 was enacted in August 2005. Among other matters, this comprehensive legislation contains provisions mandating improved electric reliability standards and performance; granting enhanced civil penalty authority to the FERC; providing economic and other incentives relating to transmission, pollution control and renewable generation assets; increasing funding for clean coal generation incentives; repealing the Public Utility Holding Company Act of 1935; enacting PUHCA 2005; and expanding FERC jurisdiction over public utility holding companies and related matters via the Federal Power Act and PUHCA 2005.

In February 2006, the Kentucky Commission initiated an administrative proceeding to consider the requirements of the EPAct 2005, Subtitle E Section 1252, Smart Metering, which concerns time-based metering and demand response, and Section 1254, Interconnections. EPAct 2005 requires each state regulatory authority to conduct a formal investigation and issue a decision on whether or not it is appropriate to implement certain Section 1252 standards within eighteen months after the enactment of EPAct 2005 and to commence consideration of Section 1254 standards within one year after the enactment of EPAct 2005. Following a public hearing with all Kentucky jurisdictional electric utilities, in December 2006, the Kentucky Commission issued an Order in this proceeding indicating that the EPAct 2005 Section 1252 and Section 1254 standards should not be adopted. However, all five Kentucky Commission jurisdictional utilities were required to file real-time pricing pilot programs for their large commercial and industrial customers. KU developed a real-time pricing pilot program for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by KU for implementation within approximately eight months. The tariff was filed in October 2008, with an effective date of December 1, 2008. KU files annual reports on the program within 90 days of each plan year end for the three-year pilot period.

Green Energy Riders

In February 2007, KU and LG&E filed a Joint Application and Testimony for Proposed Green Energy Riders. In May 2007, a Kentucky Commission Order was issued authorizing KU to establish Small and Large Green Energy Riders, allowing customers to contribute funds to be used for the purchase of renewable energy credits. During November 2009, KU and LG&E filed an application to both continue and modify the existing Green Energy Programs. In February 2010, the Kentucky Commission approved the Utilities’ application, as filed.

Home Energy Assistance Program

In July 2007, KU filed an application with the Kentucky Commission for the establishment of a Home Energy Assistance program. During September 2007, the Kentucky Commission approved the five-year

program as filed, effective in October 2007. The programs were scheduled to terminate in September 2012 and is funded through a $0.10 per month meter charge. Effective February 6, 2009, as a result of the settlement agreement in the 2008 base rate case, the program is funded through a $0.15 per month meter charge. As a condition in the settlement in the change of control proceeding before the Kentucky Commission in the PPL acquisition, the program was extended to September 2015.

Collection Cycle Revision

As part of its base rate case filed on July 29, 2008, LG&E proposed to change the due date for customer bill payments from 15 days to 10 days to align its collection cycle with KU. In addition, in its rate case filed on July 29, 2008, KU proposed to include a late payment charge if payment is not received within 15 days from the bill issuance date to align with LG&E. The settlement agreements approved in the rate cases in February 2009 changed the due date for customer bill payments to 12 days after bill issuance for both KU and LG&E and permitted KU's implementation of a late payment charge if payment is not received within 15 days from the bill issuance date.

Depreciation Study

In December 2007, KU filed a depreciation study with the Kentucky Commission as required by a previous Order. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding. The approved settlement agreements in the rate cases established new depreciation rates effective February 2009. KU also filed the depreciation study with the Virginia Commission which approved the implementation of the new depreciation rates effective February 2009. Approval by the Virginia Commission does not preclude the rates from being raised as an issue by any party in KU's future base rate cases in Virginia.

Brownfield Development Rider Tariff

In March 2008, KU received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a Brownfield site, as certified by the appropriate Kentucky state agency. The rider permits special contracts with such customers which provide for a series of declining partial rate discounts over an initial five-year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant Brownfield sites.

Interconnection and Net Metering Guidelines

In May 2008, the Kentucky Commission on its own motion initiated a proceeding to establish interconnection and net metering guidelines in accordance with amendments to existing statutory requirements for net metering of electricity. The jurisdictional electric utilities and intervenors in this case presented proposed interconnection guidelines to the Kentucky Commission in October 2008. In a January 2009 Order, the Kentucky Commission issued the Interconnection and Net Metering Guidelines – Kentucky that were developed by all parties to the proceeding. KU does not expect any financial or other impact as a result of this Order. In April 2009, KU filed revised net metering tariffs and application forms pursuant to the Kentucky Commission's Order. The Kentucky Commission issued an Order in April 2009, which suspended for five months all net metering tariffs filed by the jurisdictional

electric utilities. This suspension was intended to allow sufficient time for review of the filed tariffs by the Kentucky Commission Staff and intervening parties. In June 2009, the Kentucky Commission Staff held an informal conference with the parties to discuss issues related to the net metering tariffs filed by KU. Following this conference, the intervenors and KU resolved all issues and KU filed revised net metering tariffs with the Kentucky Commission. In August 2009, the Kentucky Commission issued an Order approving the revised tariffs.

EISA 2007 Standards

In November 2008, the Kentucky Commission initiated an administrative proceeding to consider new standards as a result of the Energy Independence and Security Act of 2007 ("EISA 2007"), part of which amends the Public Utility Regulatory Policies Act of 1978 ("PURPA"). There are four new PURPA standards and one non-PURPA standard applicable to electric utilities. The proceeding also considers two new PURPA standards applicable to natural gas utilities. EISA 2007 requires state regulatory commissions and non-regulated utilities to begin consideration of the rate design and smart grid investments no later than December 19, 2008 and to complete the consideration by December 19, 2009. The Kentucky Commission established a procedural schedule that allowed for data discovery and testimony through July 2009. In October 2009, the Kentucky Commission held an informal conference for the purpose of discussing issues related to the standard regarding the consideration of Smart Grid investments. A public hearing has not been scheduled in this matter.

Note 4 - Asset Retirement Obligations

A summary of KU's net ARO assets, ARO liabilities and regulatory assets established under the asset retirement and environmental obligations guidance of the FASB ASC follows:

	ARO Net Assets	ARO Liabilities	Regulatory Assets
As of December 31, 2008, Predecessor	$ 5	$ (32)	$ 28
ARO accretion and depreciation	(1)	(2)	2
As of December 31, 2009, Predecessor	4	(34)	30
ARO accretion and depreciation	-	(2)	2
Reclassification for retired assets	(1)	-	1
ARO revaluation - change in estimates	22	(24)	2
As of October 31, 2010, Predecessor	25	(60)	35
ARO accretion and depreciation	(1)	-	1
Purchase accounting - fair value adjustment	28	6	(34)
As of December 31, 2010, Successor	$ 52	$ (54)	$ 2

In September 2010, the Company performed a revaluation of its AROs as a result of recently proposed environmental legislation and improved ability to forecast asset retirement costs due to recent construction and retirement activity.

In November 2010, the Company recorded a purchase accounting adjustment to fair value AROs due to the PPL acquisition.

Pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC, an offsetting regulatory credit was recorded in “Depreciation and amortization” in the Statements of Income for the Successor of $1 million in 2010 and $2 million for the Predecessor for the ARO accretion and depreciation expense. The offsetting regulatory credit recorded was $2 million in 2009 and 2008 for the ARO accretion and depreciation expense. The ARO liabilities are offset by cash settlements that have not yet been applied. Therefore, ARO net assets, ARO liabilities and regulatory assets balances do not net to zero due to the cash settlements.

KU’s AROs are primarily related to the final retirement of assets associated with generating units. KU transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under the asset retirement and environmental obligations guidance of the FASB ASC, no material asset retirement obligations are recorded for transmission and distribution assets.

Note 5 – Derivative Financial Instruments

KU is subject to interest rate and commodity price risk related to on-going business operations. The Company’s policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. Although the Company’s policies allow for the use of interest rate swaps, as of December 31, 2010 and 2009, KU had no interest rate swaps outstanding. At December 31, 2010, KU’s potential annual exposure to increased interest expense, based on a 10% increase in interest rates, was less than $1 million.

The Company does not net collateral against derivative instruments.

Energy Trading and Risk Management Activities

KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to manage price risk and are accounted for as non-hedging derivatives on a mark-to-market basis in accordance with the derivatives and hedging guidance of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from Intercontinental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity data is unavailable, other inputs include prices quoted by brokers or observable inputs other than quoted prices, such as one-sided bids or offers as of the balance sheet date. Quotes are verified quarterly using an independent pricing source of actual transactions. Quotes for combined off-peak and weekend timeframes are allocated between the two timeframes based on their historical proportional ratios to the integrated cost. No other adjustments are made to the forward prices. No changes to valuation techniques for energy trading and risk management activities occurred during 2010 or 2009. Changes in market pricing, interest rate and volatility assumptions were made during both years.

KU's financial assets and liabilities as of December 31, 2010 and December 31, 2009, arising from energy trading and risk management contracts not designated as hedging instruments accounted for at fair value total less than $1 million and are recorded in prepayments and other current assets and other current liabilities, respectively.

The Company maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, KU seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. The Company uses ratings of S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, KU assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At December 31, 2010, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. The Company has reserved against counterparty credit risk based on KU's own creditworthiness (for net liabilities) and its counterparty's creditworthiness (for net assets). The Company applies historical default rates within varying credit ratings over time provided by S&P or Moody's. At December 31, 2010 and December 31, 2009, counterparty credit reserves related to energy trading and risk management contracts were less than $1 million.

The net volume of electricity based financial derivatives outstanding at December 31, 2010 and December 31, 2009, was 129,199 Mwh and 315,600 Mwh, respectively. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2010 and December 31, 2009. Cash collateral related to the energy trading and risk management contracts is recorded in "Prepayments and other current assets" on the Balance Sheets.

KU manages the price risk of its estimated future excess economic generation capacity using market-traded forward contracts. Hedge accounting treatment has not been elected for these transactions; therefore, realized and unrealized gains and losses are included in the Statements of Income.

The following table presents the effect of market-traded forward contract derivatives not designated as hedging instruments on income:

		Successor	Predecessor		
Loss Recognized in Income	Location	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Unrealized gain (loss)	Electric revenues	$ -	$ -	$ (1)	$ 1

Net realized gains and losses were zero for the period ended December 31, 2010 and less than $1 million for the periods ended October 31, 2010, December 31, 2009 and December 31, 2008.

Credit Risk Related Contingent Features

Certain of KU's derivative contracts contain credit contingent provisions which would permit the counterparties with which KU is in a net liability position to require the transfer of additional collateral upon a decrease in KU's credit rating. Some of these provisions would require KU to transfer additional collateral or permit the counterparty to terminate the contract if KU's credit rating were to fall below investment grade. Some of these provisions also allow the counterparty to require additional collateral upon each decrease in the credit rating at levels that remain above investment grade. In either case, if KU's credit rating were to fall below investment grade (i.e., below BBB- for S&P or Baa3 for Moody's), and assuming no assignment to an investment grade affiliate were allowed, most of these credit contingent provisions require either immediate payment of the net liability as a termination payment or immediate and ongoing full collateralization by KU on derivative instruments in net liability positions.

Additionally, certain of KU's derivative contracts contain credit contingent provisions that require KU to provide "adequate assurance" of performance if the other party has reasonable grounds for insecurity regarding KU's performance of its obligation under the contract. A counterparty demanding adequate assurance could require a transfer of additional collateral or other security, including letters of credit, cash and guarantees from a creditworthy entity. A demand for additional assurance would typically involve negotiations among the parties.

To determine net liability positions, KU uses the fair value of each agreement. At December 31, 2010, there were no energy trading and risk management derivative contracts with credit risk related contingent features that are in a liability position and collateral of less than $1 million was posted in the normal course of business. At December 31, 2010, a downgrade of the Company's credit rating below investment grade would have no effect on the energy trading and risk management derivative contracts or collateral required.

Note 6 - Fair Value Measurements

KU adopted the fair value guidance in the FASB ASC in two phases. Effective January 1, 2008, the Company adopted it for all financial instruments and non-financial instruments accounted for at fair value on a recurring basis, and effective January 1, 2009, the Company adopted it for all non-financial instruments accounted for at fair value on a non-recurring basis. The FASB ASC guidance clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. As a basis for considering such assumptions, the FASB ASC guidance establishes a three-tier value hierarchy, which prioritizes the inputs used in the valuation methodologies in measuring fair value.

The carrying values and estimated fair values of KU's non-trading financial instruments follow:

	Successor		Predecessor	
	December 31, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term bonds	$ 1,841	$ 1,728	$ 351	$ 351
Long-term debt to affiliated company	-	-	1,331	1,401

The long-term fixed rate pollution control bond valuations reflect prices quoted by investment banks, which are active in the market for these instruments. First mortgage bond valuations reflect prices quoted from a third party service. The fair value of the long-term debt due to affiliated company is determined using an internal valuation model that discounts the future cash flows of each loan at current market rates as determined based on quotes from investment banks that are actively involved in capital markets for utilities and factor in KU's credit ratings and default risk. The fair values of cash and cash equivalents, accounts receivable, cash surrender value of key man life insurance, accounts payable and notes payable are substantially the same as their carrying values.

KU has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures guidance of the FASB ASC, as discussed in Note 1, Summary of Significant Accounting Policies.

The Company classifies its derivative cash collateral balances within level 1 based on the funds being held in a demand deposit account. The Company classifies its derivative energy trading and risk management contracts within level 2 because it values them using prices actively quoted for proposed or executed transactions, quoted by brokers or observable inputs other than quoted prices.

KU's financial assets and liabilities as of December 31, 2010 and 2009, arising from energy trading and risk management contracts accounted for at fair value on a recurring basis total less than $1 million. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2010 and December 31, 2009 each year.

There were no level 3 measurements for the periods ending December 31, 2010 and December 31, 2009.

Note 7 - Goodwill and Intangible Assets

In connection with PPL's acquisition of LKE, KU recorded goodwill on November 1, 2010. In addition, as of November 1, 2010, certain intangible assets were adjusted to their fair value and new intangible assets were recorded. See Note 2, Acquisition by PPL, for further information.

<u>Goodwill</u>

The Company performs its required annual goodwill impairment test in the fourth quarter. Impairment tests are performed between the annual tests when the Company determines that a triggering event has occurred that would, more likely than not, reduce the fair value of a reporting unit below its carrying value. The goodwill impairment test is comprised of a two-step process. In step 1, the Company identifies a potential impairment by comparing the estimated fair value of the regulated utilities (the

goodwill reporting unit) to their carrying value, including goodwill, on the measurement date. If the estimated fair value exceeds its carrying amount, goodwill is not considered impaired. If the fair value is less than the carrying value, then step 2 is performed to measure the amount of impairment loss, if any. The step 2 calculation compares the implied fair value of the goodwill to the carrying value of the goodwill. The implied fair value of goodwill is equal to the excess of the Company estimated fair value over the fair values of its identified assets and liabilities. If the carrying value of goodwill exceeds the implied fair value of goodwill, an impairment loss is recognized in an amount equal to that excess (but not in excess of the carrying value).

In connection with PPL's acquisition of LKE on November 1, 2010, goodwill of $607 million was recorded on November 1, 2010. The allocation of the goodwill to KU was based on the net asset value of the Company. The goodwill represents value paid for the rate regulated business located in a defined service area with a constructive regulatory environment, which provides for future investment, earnings and cash flow growth, as well as the talented and experienced workforce. KU's franchise values are being attributed to the going concern value of the business and thus were recorded as goodwill rather than a separately identifiable intangible asset. None of the goodwill recognized is expected to be deductible for income tax purposes or included in customer rates. See Note 2, Acquisition by PPL, for further information.

For the 2010 annual impairment test, the primary valuation technique used was an income methodology based on management's estimates of forecasted cash flows for the Company, with those cash flows discounted to present value using rates commensurate with the risks of those cash flows. Management also took into consideration the acquisition price paid by PPL. The discounted cash flows for the Company was based on discrete financial forecasts developed by management for planning purposes and consistent with those given to PPL. Cash flows beyond the discrete forecasts were estimated using a terminal-value calculation, which incorporated historical and forecasted financial trends for the Company. No impairment resulted from the fourth quarter test, as the determined fair value of the Company was greater than its carrying value.

Other Intangible Assets

The gross carrying amount and the accumulated amortization of other intangible assets were as follows:

	Successor	
	December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:		
Coal contracts (a)	$ 145	$ 3
Land rights (b)	8	-
Emission allowances (c)	9	-
OVEC power purchase agreement (d)	39	1
Total other intangible assets	$ 201	$ 4

(a) The gross carrying amount represents the fair value of coal contracts recognized as a result of the 2010 acquisition by PPL. The weighted average amortization period of these contracts is 3 years. See Note 2, Acquisition by PPL, for further information.

(b) The gross carrying amount represents the fair value of land rights recognized as a result of adopting PPL's accounting policies in the Successor period. The weighted average amortization period of these rights is 17 years. See Note 1, Summary of Significant Accounting Policies, for further information.

(c) The gross carrying amount represents the fair value of emission allowances recognized as a result of the 2010 acquisition by PPL, as well as the reclassification of amounts from inventory to intangible assets as a result of adopting PPL's accounting policies in the Successor period. The weighted average amortization period of these emission allowances is 3 years. See Note 2, Acquisition by PPL, for further information.

(d) The gross carrying amount represents the fair value of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. The weighted average amortization period of the power purchase agreement is 8 years. See Note 2, Acquisition by PPL, for further information.

Current intangible assets and long-term intangible assets are included in "Other intangible assets" in their respective areas on the Balance Sheets in 2010. Intangible assets resulting from purchase accounting adjustments are not recoverable in rates.

Amortization expense, excluding consumption of emission allowances, was $4 million for the Successor in 2010. The estimated aggregate amortization expense for each of the next five years is as follows:

	Estimated Expense in Period Ended				
	2011	2012	2013	2014	2015
Aggregate amortization expense	$ 43	$ 25	$ 27	$ 24	$ 26

Note 8 - Concentrations of Credit and Other Risk

Credit risk represents the accounting loss that would be recognized at the reporting date if counterparties failed to perform as contracted. Concentrations of credit risk (whether on- or off-balance sheet) relate to groups of customers or counterparties that have similar economic or industry characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

All of KU's customer receivables arise from deliveries of electricity. During 2010, the Company's ten largest customers accounted for less than 19% of volumes.

Effective August 4, 2009, KU and its employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement. The agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. KU and its employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement in August 2008. This agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. The employees represented by these two bargaining units comprise approximately 15% of the Company's workforce at December 31, 2010.

Note 9 - Pension and Other Postretirement Benefit Plans

KU employees benefit from both funded and unfunded retirement benefit plans. Its defined benefit pension plan covers employees hired by December 31, 2005. Employees hired after this date participate in the Retirement Income Account ("RIA"), a defined contribution plan. The postretirement plan includes health care benefits that are contributory, with participants' contributions adjusted annually. The Company uses December 31 as the measurement date for its plans.

Obligations and Funded Status

The following tables provide a reconciliation of the changes in the defined benefit plans' obligations, the fair value of assets and the funded status of the plans for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 355	$ 316	$ 306	$ 84	$ 80	$ 75
Service cost	1	5	6	-	1	2
Interest cost	3	16	18	1	4	4
Benefits paid, net of retiree contributions	(3)	(14)	(18)	(1)	(4)	(5)
Actuarial (gain) loss and other	(2)	32	4	(1)	3	4
Benefit obligation at end of period	$ 354	$ 355	$ 316	$ 83	$ 84	$ 80

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 237	$ 219	$ 183	$ 20	$ 17	$ 12
Actual return on plan assets	7	20	41	-	1	3
Employer contributions	-	13	13	2	6	7
Benefits paid, net of retiree contributions	(3)	(14)	(18)	(1)	(4)	(5)
Administrative expenses and other	-	(1)	-	-	-	-
Fair value of plan assets at end of period	$ 241	$ 237	$ 219	$ 21	$ 20	$ 17
Funded status at end of period	$ (113)	$ (118)	$ (97)	$ (62)	$ (64)	$ (63)

Amounts Recognized in the Balance Sheets

The following tables provide the amounts recognized in the Balance Sheets and information for plans with benefit obligations in excess of plan assets plans for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Regulatory assets	$ 117	$ 125	$ 105	$ -	$ -	$ -
Regulatory liabilities	-	-	-	(10)	(9)	(9)
Accrued benefit liability (non-current)	(113)	(118)	(97)	(62)	(64)	(63)

Amounts recognized in regulatory assets and liabilities for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Transition obligation	$ -	$ -	$ -	$ 2	$ 2	$ 3
Prior service cost	3	4	5	1	1	2
Accumulated loss (gain)	114	121	100	(13)	(12)	(14)
Total regulatory assets and liabilities	$ 117	$ 125	$ 105	$ (10)	$ (9)	$ (9)

Additional information for plans with accumulated benefit obligations in excess of plan assets for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Benefit obligation	$ 354	$ 355	$ 316	$ 83	$ 84	$ 80
Accumulated benefit obligation	299	299	268	-	-	-
Fair value of plan assets	241	237	219	21	20	17

The amounts recognized in regulatory assets and liabilities for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Net (gain) loss arising during the period	$ (6)	$ 26	$ (22)	$ (1)	$ 2	$ 2
Amortization of prior service cost	-	(1)	(1)	-	-	-
Amortization of transitional obligation	-	-	-	-	(2)	(1)
Amortization of loss	(2)	(5)	(9)	-	-	-
Total amounts recognized in regulatory assets and liabilities	$ (8)	$ 20	$ (32)	$ (1)	$ -	$ 1

For discussion of the pension and postretirement regulatory assets, see Note 3, Rates and Regulatory Matters.

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost for pension and other postretirement benefit plans. The tables include the costs associated with both KU employees and Servco employees who provide services to KU. The Servco costs are allocated to KU based on employees' labor charges and are approximately 51%, 49% and 46% of Servco's costs for 2010, 2009 and 2008, respectively.

	Pension Benefits					
	Successor			Predecessor		
	November 1, 2010 through December 31, 2010			January 1, 2010 through October 31, 2010		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 1	$ 1	$ 2	$ 5	$ 5	$ 10
Interest cost	3	2	5	16	6	22
Expected return on plan assets	(3)	(1)	(4)	(14)	(5)	(19)
Amortization of prior service cost	-	-	-	1	1	2
Amortization of actuarial gain	2	-	2	5	2	7
Net periodic benefit cost	$ 3	$ 2	$ 5	$ 13	$ 9	$ 22

	Pension Benefits					
	Predecessor - Year Ended December 31, 2009			Predecessor - Year Ended December 31, 2008		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 6	$ 5	$ 11	$ 6	$ 4	$ 10
Interest cost	18	7	25	18	6	24
Expected return on plan assets	(15)	(4)	(19)	(21)	(5)	(26)
Amortization of prior service cost	1	1	2	1	1	2
Amortization of actuarial gain	9	2	11	-	-	-
Net periodic benefit cost	$ 19	$ 11	$ 30	$ 4	$ 6	$ 10

	Other Postretirement Benefits					
	Successor			Predecessor		
	November 1, 2010 through December 31, 2010			January 1, 2010 through October 31, 2010		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ -	$ -	$ -	$ 1	$ 1	$ 2
Interest cost	1	-	1	4	-	4
Expected return on plan assets	-	-	-	(1)	-	(1)
Amortization of transition obligation	-	-	-	1	-	1
Net periodic benefit cost	$ 1	$ -	$ 1	$ 5	$ 1	$ 6

	Other Postretirement Benefits					
	Predecessor - Year Ended December 31, 2009			Predecessor Year Ended December 31, 2008		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	5	-	5	5	-	5
Expected return on plan assets	(1)	-	(1)	(1)	-	(1)
Amortization of transition obligation	1	-	1	1	-	1
Net periodic benefit cost	$ 6	$ 1	$ 7	$ 6	$ 1	$ 7

The estimated amounts that will be amortized from regulatory assets and liabilities into net periodic benefit cost in 2011 are shown in the following table:

	Pension Benefits	Other Postretirement Benefits
Regulatory assets and liabilities:		
Net actuarial loss	$ 8	$ -
Prior service cost	1	1
Transition obligation	-	1
Total regulatory assets and liabilities amortized during 2011	$ 9	$ 2

The weighted average assumptions used in the measurement of KU's pension and postretirement benefit obligations for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor are shown in the following table:

	Successor	Predecessor	
	December 31, 2010	October 31, 2010	December 31, 2009
Discount rate – pension benefits	5.52%	5.46%	6.13%
Discount rate – postretirement benefits	5.12%	4.96%	5.82%
Rate of compensation increase	5.25%	5.25%	5.25%

For the first ten months of 2010, the discount rates used to determine the pension and postretirement benefit obligations and the period expense were determined using the Mercer Pension Discount Yield Curve. This model takes the plans' cash flows and matches them to a yield curve that provides the equivalent yields on zero-coupon corporate bonds for each maturity. The discount rate is the single rate

that produces the same present value of cash flows. The selection of the various discount rates represents the equivalent single rate under a broad-market AA yield curve constructed by Mercer.

For the last two months of 2010, the Towers Watson Yield Curve was used to determine the discount rate. This model also starts with an analysis of the expected benefit payment stream for its plans. This information is first matched against a spot-rate yield curve. A portfolio of Aa-graded non-callable (or callable with make-whole provisions) bonds, with a total amount outstanding in excess of $667 billion, serves as the base from which those with the lowest and highest yields are eliminated to develop the ultimate yield curve. The results of this analysis are considered together with other economic data and movements in various bond indices to determine the discount rate assumption.

The weighted average assumptions used in the measurement of KU's pension and postretirement net periodic benefit costs for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor are shown in the following table:

	Successor	Predecessor		
	2010	2010	2009	2008
Discount rate - pension	5.45%	5.46%	6.25%	6.66%
Discount rate - postretirement	4.94%	5.82%	6.36%	6.56%
Expected long-term return on plan assets	7.25%	7.75%	8.25%	8.25%
Rate of compensation increase	5.25%	5.25%	5.25%	5.25%

To develop the expected long-term rate of return on assets assumption, KU considered the current level of expected returns on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the current asset allocation to develop the expected long-term rate of return on assets assumption for the portfolio. The Company has determined that the 2011 expected long-term rate of return on assets assumption should be 7.25%.

The following describes the effects on pension benefits by changing the major actuarial assumptions discussed above:

- A 1% change in the assumed discount rate would have a $39 million positive or negative impact to the 2010 accumulated benefit obligation and an approximate $51 million positive or negative impact to the 2010 projected benefit obligation.
- A 25 basis point change in the expected rate of return on assets would have resulted in less than a $1 million positive or negative impact to 2010 pension expense.
- A 25 basis point increase in the rate of compensation increase would have a $3 million negative impact to the 2010 projected benefit obligation.

Assumed Health Care Cost Trend Rates

For measurement purposes, an 8% annual increase in the per capita cost of covered health care benefits was assumed for the first ten months of 2010. The rate was assumed to decrease gradually to 4.5% by 2029 and remain at that level thereafter. For the last two months of 2010, an 8% annual increase in the

per capita cost of covered health care benefits was assumed and the rate was assumed to decrease gradually to 5.5% by 2019. For 2011, a 9% annual increase in the per capita cost of covered health care benefits is assumed and the rate is assumed to decrease gradually to 5.5% by 2019. This change in the length of the health care trend was made to conform to PPL's accounting policies.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in assumed health care cost trend rates would have resulted in an increase or decrease of less than $1 million to the 2010 total of service and interest costs components and an increase or decrease of $4 million in year end 2010 postretirement benefit obligations.

Expected Future Benefit Payments and Medicare Subsidy Receipts

The following list provides the amount of expected future benefit payments, which reflect expected future service costs and the estimated gross amount of Medicare subsidy receipts:

	Pension Benefits	Other Postretirement Benefits	Medicare Subsidy Receipts
2011	$ 18	$ 6	$ 1
2012	18	6	-
2013	18	6	1
2014	18	7	-
2015	18	7	1
2016-2020	106	36	3

Plan Assets

The following table shows the pension plan's weighted average asset allocation by asset category at December 31:

	Target Range	Successor 2010	Predecessor 2009
Equity securities	45% - 75%	56%	59%
Debt securities	30% - 50%	24%	40%
Other	0% - 10%	20%	1%
Totals		100%	100%

The investment policy of the pension plans was developed in conjunction with financial and actuarial consultants, investment advisors and legal counsel. The goal of the investment policy is to preserve the capital of the pension plans' assets and maximize investment earnings in excess of inflation with acceptable levels of volatility. The return objective is to exceed the benchmark return for the policy index comprised of the following: Russell 3000 Index, MSCI-EAFE Index, Barclays Capital Aggregate and Barclays Capital U.S. Long Government/Credit Bond Index in proportions equal to the targeted asset allocation.

Evaluation of performance focuses on a long-term investment time horizon over rolling three and five-year periods. The assets of the pension plans are broadly diversified within different asset classes (equities, fixed income securities and cash equivalents).

To minimize the risk of large losses in a single asset class, no more than 5% of the portfolio will be invested in the securities of any one issuer with the exclusion of the U.S. government and its agencies. The equity portion of the fund is diversified among the market's various subsections to diversify risk, maximize returns and avoid undue exposure to any single economic sector, industry group or individual security. The equity subsectors include, but are not limited to, growth, value, small capitalization and international.

In addition, the overall fixed income portfolio may have an average weighted duration, or interest rate sensitivity which is within +/- 20% of the duration of the overall fixed income benchmark. Foreign bonds in the aggregate shall not exceed 10% of the total fund. The portfolio may include a limited investment of up to 20% in below investment grade securities provided that the overall average portfolio quality remains "AA" or better. The below investment grade securities include, but are not limited to, medium-term notes, corporate debt, non-dollar and emerging market debt and asset backed securities. The cash investments should be in securities that are either short maturities (not to exceed 180 days) or readily marketable with modest risk.

Derivative securities are permitted only to improve the portfolio's risk/return profile, to modify the portfolio's duration or to reduce transaction costs and must be used in conjunction with underlying physical assets in the portfolio. Derivative securities that involve speculation, leverage, interest rate anticipation, or any undue risk whatsoever are not deemed appropriate investments.

The investment objective for the postretirement benefit plan is to provide current income consistent with stability of principal and liquidity while maintaining a stable net asset value of $1.00 per share. The postretirement funds are invested in a prime cash money market fund that invests primarily in a portfolio of short-term, high-quality fixed income securities issued by banks, corporations and the U.S. government.

KU has classified plan assets that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures guidance of the FASB ASC. See Note 6, Fair Value Measurements, for further information.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs.

A description of the valuation methodologies used to measure plan assets at fair value is provided below:

> *Money market funds*: These investments are public investment vehicles valued using $1 for the net asset value. The money market funds are classified within level 2 of the valuation hierarchy.
>
> *Common/collective trusts:* Valued based on the beginning of year value of the plan's interests in the trust plus actual contributions and allocated investment income (loss) less actual distributions and allocated administrative expenses. Quoted market prices are used to value investments in the trust, with the exception of the GAC. The fair value of certain other investments for which quoted market prices are not available are valued based on yields currently available on

comparable securities of issuers with similar credit ratings. The common/collective trusts are classified within level 2 of the valuation hierarchy.

The preceding methods described may produce a fair value that may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

Prior to the acquisition, the GAC was considered an immediate participation guarantee contract which was not included in the fair value table. In accordance with the plan accounting guidance of the FASB ASC, the cost incurred to purchase the GAC prior to March 20, 1992, was permitted to be carried at contract value, since it is a contract with an insurance company and prior to the acquisition it was excluded from the table above. The cost incurred to fund the GAC after March 20, 1992, was carried at contract value in accordance with the plan accounting guidance of the FASB ASC, since it was a contract that incorporates mortality and morbidity risk. Contract value represents cost plus interest income less distributions for benefits and administrative expenses. To conform to PPL's accounting methods, the John Hancock GAC was classified in the fair value table as a level 3 and as "other" rather than "debt securities" in the asset allocation table for the period ended December 31, 2010.

The following table sets forth, by level within the fair value hierarchy, the plan's assets at fair value at December 31:

	Successor		Predecessor	
	Level 2	Level 3	Level 2	Level 3
Money market funds	$ 2	$ -	$ 2	$ -
Common/collective trusts	213	-	186	-
John Hancock - GAC	-	47	-	-
Total investments at fair value	$ 215	$ 47	$ 188	$ -

The following table sets forth a reconciliation of changes in the fair value of the plan's level 3 assets for the following period:

	Successor
Balance at November 1, 2010	$ -
Purchases	1
Transfers into level 3	46
Balance at December 31, 2010	$ 47

There are no assets categorized as level 1 as of December 31, 2010 and December 31, 2009.

Contributions

KU made discretionary contributions to the pension plan of $13 million in 2010 and 2009. Servco made $9 million and $8 million in discretionary contributions to its pension plan in 2010 and 2009, respectively. The amount of future contributions to the pension plan will depend upon the actual return on plan assets and other factors, but the Company funds its pension obligations in a manner consistent

with the Pension Protection Act of 2006. The Company made contributions totaling $43 million in January 2011.See Note 18, Subsequent Events, for further information.

The Company made contributions to its other postretirement benefit plan of $8 million in 2010 and $7 million in 2009. In 2011, the Company anticipates making voluntary contributions to fund Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Pension Legislation

The Pension Protection Act of 2006 was enacted in August 2006. New rules regarding funding of defined benefit plans are generally effective for plan years beginning in 2008. Among other matters, this comprehensive legislation contains provisions applicable to defined benefit plans which generally (i) mandate full funding of current liabilities within seven years; (ii) increase tax-deduction levels regarding contributions; (iii) revise certain actuarial assumptions, such as mortality tables and discount rates; and (iv) raise federal insurance premiums and other fees for under-funded and distressed plans. The legislation also contains a number of provisions relating to defined-contribution plans and qualified and non-qualified executive pension plans and other matters. The Company's plan met the minimum funding requirements as defined by the Pension Protection Act of 2006 for years ended December 31, 2010 and 2009.

Thrift Savings Plans

KU has a thrift savings plan under section 401(k) of the Internal Revenue Code. Under the plan, eligible employees may defer and contribute to the plan a portion of current compensation in order to provide future retirement benefits. KU makes contributions to the plan by matching a portion of the employees' contributions. The costs of this matching were $3 million in 2010, 2009 and 2008.

KU also makes contributions to RIAs within the thrift savings plans for certain employees not covered by the non-contributory defined benefit pension plan. These employees consist of those hired after December 31, 2005. The Company makes these contributions based on years of service and the employees' wage and salary levels, and makes them in addition to the matching contributions discussed above. The amounts contributed by the Company under this arrangement were less than $1 million in 2010, 2009 and 2008.

Health Care Reform

In March 2010, Health Care Reform (the Patient Protection and Affordable Care Act of 2010) was signed into law. Many provisions of Health Care Reform do not take effect for an extended period of time and many aspects of the law which are currently unclear or undefined will likely be clarified in future regulations.

During 2010, KU recorded an income tax expense of less than $1 million to recognize the impact of the elimination of the tax deduction related to the Medicare Retiree Drug Subsidy that becomes effective in 2013.

Specific provisions within Health Care Reform that may impact KU include:

- Beginning in 2011, requirements extend dependent coverage up to age 26, remove the $2 million lifetime maximum and eliminate cost sharing for certain preventative care procedures.
- Beginning in 2018, a potential excise tax is expected on high-cost plans providing health coverage that exceeds certain thresholds.

The Company has evaluated these provisions of Health Care Reform on its benefit programs in consultation with its actuarial consultants and has determined that the excise tax will not have an impact on its postretirement medical plans. The requirement to extend dependent coverage up to age 26 is not expected to have a significant impact on active or retiree medical costs. The Company will continue to monitor the potential impact of any changes to the existing provisions and implementation guidance related to Health Care Reform on its benefit programs.

Note 10 - Income Taxes

KU's federal income tax return is included in a United States consolidated income tax return filed by LKE's direct parent. Prior to October 31, 2010 the return was included in the consolidated return of E.ON US Investments Corp. Due to the acquisition by PPL, the return will be included in the consolidated PPL return beginning November 1, 2010, for each tax period. Each subsidiary of the consolidated tax group, including KU, calculates its separate income tax for each period. The resulting separate-return tax cost or benefit is paid to or received from the parent company or its designee. The Company also files income tax returns in various state jurisdictions. While 2007 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2007-2008 have been received from the IRS, effectively closing these years to additional audit adjustments. Tax years beginning with 2007 were examined under an IRS program, Compliance Assurance Process ("CAP"). This program accelerates the IRS's review to begin during the year applicable to the return and ends 90 days after the return is filed. KU had no adjustments for the 2007 federal tax return. For 2008, the IRS allowed additional deductions in connection with the Company's application for a change in repair deductions and disallowed certain bonus depreciation claimed on the original return. The net temporary tax impact for the Company was a $12 million reduction in tax and was recorded in the second quarter of 2010. The 2009 federal return was filed in the third quarter of 2010 and the IRS issued a Partial Acceptance Letter in connection with CAP. The IRS is continuing to review bonus depreciation, storms and other repairs. No net material adverse impact is expected from these remaining areas. The short tax year beginning January 1, 2010 through October 31, 2010, is also being examined under CAP. No material items have been raised by the IRS at this time. The two month period beginning November 1, 2010 and ending December 31, 2010 is not currently under examination.

Additions and reductions of uncertain tax positions during 2010, 2009 and 2008 were less than $1 million. Possible amounts of uncertain tax positions for KU that may decrease within the next 12 months total less than $1 million and are based on the expiration of the audit periods as defined in the statutes. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

The amount KU recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million for the twelve month periods ended and as of December 31, 2010, 2009 and 2008. The interest expense and interest accrued is based on IRS and Kentucky Department of Revenue

large corporate interest rates for underpayment of taxes. At the date of adoption, the Company accrued less than $1 million in interest expense on uncertain tax positions. KU records the interest as “Interest expense” and penalties, if any, as “Operating expenses” on the Statements of Income and “Other current liabilities” on the Balance Sheets, on a pre-tax basis. No penalties were accrued by the Company through December 31, 2010.

Components of income tax expense are shown in the table below:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Current:				
Federal	$ 13	$ 46	$ (5)	$ 46
State	3	9	1	10
Deferred:				
Federal – net	4	20	43	(10)
State – net	-	3	7	(3)
Investment tax credit – deferred	-	-	21	25
Total income tax expense	$ 20	$ 78	$ 67	$ 68

In June 2006, KU and LG&E filed a joint application with the U.S. Department of Energy (“DOE”) requesting certification to be eligible for an investment tax credit applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that KU and LG&E were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, KU received an Order from the Kentucky Commission approving the accounting of the investment tax credit, which includes a full depreciation basis adjustment for the amount of the credit. KU’s portion of the TC2 tax credit is approximately $101 million. Based on eligible construction expenditures incurred, KU recorded an investment tax credit of $21 million and $25 million in 2009 and 2008, respectively, decreasing current federal income taxes. As of December 31, 2009, KU had recorded its maximum credit of $101 million. The income tax expense impact from amortizing this credit over the life of the related property began when the facility was placed in service in January 2011.

In March 2008, certain environmental and preservation groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was in violation of certain environmental laws and demanded relief, including suspension or termination of the program. The plaintiffs voluntarily dismissed their complaint in August 2010.

Components of deferred income taxes included in the Balance Sheets are shown below:

	Successor December 31, 2010	Predecessor December 31, 2009
Deferred income tax liabilities:		
Depreciation and other plant-related items	$ 347	$ 303
Regulatory assets and other	133	69
Total deferred income tax liabilities	480	372
Deferred income tax assets:		
Regulatory liabilities and other	80	-
Income taxes due to customers	2	4
Pensions and related benefits	9	17
Liabilities and other	19	18
Total deferred income tax assets	110	39
Net deferred income tax liabilities	$ 370	$ 333
Balance sheet classification:		
Prepayments and other current assets	$ (6)	$ (3)
Deferred income taxes (non-current)	376	336
Net deferred income tax liabilities	$ 370	$ 333

The Company expects to have adequate levels of taxable income to realize its recorded deferred income tax assets.

A reconciliation of differences between the income tax expense at the statutory U.S. federal income tax rate and KU's actual income tax expense follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,	
			2009	2008
Statutory federal income tax expense	$ 19	$ 77	$ 70	$ 79
State income taxes – net of federal benefit	2	8	5	5
Qualified production activities deduction	(1)	(4)	(1)	(3)
Dividends received deduction related to EEI investment	-	-	(3)	(8)
Reversal of excess deferred taxes	-	(2)	(2)	(1)
Other differences – net	-	(1)	(2)	(4)
Income tax expense	$ 20	$ 78	$ 67	$ 68
Effective income tax rate	36.4%	35.8%	33.5%	30.1%

The Tax Relief, Unemployment Reauthorization and Job Creation Act of 2010, enacted December 17, 2010 provided, among other provisions, certain incentives related to bonus depreciation and 100% expensing of qualifying capital expenditures. KU benefited from these new provisions by reducing its 2010 current federal income tax expense. This reduction in federal taxable income for KU does, however, result in a reduction of KU's Section 199 Manufacturing deduction, which is based on manufacturing taxable income and correspondingly increases income tax expense. The impact from these changes on 2010 was not material; however, KU anticipates a significant reduction of taxable income in 2011 and 2012 and a corresponding loss of most, if not all, of the Section 199 Manufacturing deduction for the following two years.

Note 11 - Long-Term Debt

As summarized below, at December 31, 2010, long-term debt consisted of first mortgage bonds and secured pollution control bonds. At December 31, 2009, long-term debt and the current portion of long-term debt consisted primarily of pollution control bonds and long-term loans from affiliated companies.

	Successor		Predecessor	
	2010		2009	
Current portion of long-term debt to affiliates	$	-	$	33
Long-term debt to affiliated companies		-		1,298
Secured first mortgage bonds, net of debt discount and amortization of debt discount		1,500		-
Pollution control revenue bonds, collateralized by first mortgage bonds		351		351
Fair value adjustment from purchase accounting		1		-
Unamortized discount		(11)		-
Total long-term debt		1,841		1,682
Less current portion		-		261
Long-term debt, excluding current portion	$	1,841	$	1,421

	Stated Interest Rates	Maturities		Debt Amounts
Successor				
Outstanding at December 31, 2010:				
Current portion	N/A	N/A	$	-
Non-current portion	Variable – 6.00%	2015-2040		1,841
Predecessor				
Outstanding at December 31, 2009:				
Current portion	Variable – 4.240%	2010-2034	$	261
Non-current portion	Variable – 7.035%	2011-2037		1,421

As of December 31, 2009, long-term debt includes $228 million of pollution control bonds that were classified as current portion because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include Carroll County 2002 Series A and B, 2004 Series A, 2006 Series B and 2008 Series A; Muhlenberg County 2002 Series A; and Mercer County 2000 Series A and 2002 Series A. Maturity dates for these bonds range from 2023 to 2034. As of December 31, 2009, the bonds were classified as current portion of long-term debt because investors could put the bonds back to the Company within one year. As of December 31, 2010, the bonds were reclassified as long-term debt. See Note 1, Summary of Significant Accounting Policies, for changes in classification.

Pollution control bonds are obligations of KU issued in connection with tax-exempt pollution control bonds by various counties in Kentucky. A loan agreement obligates the Company to make debt service payments to the counties in amounts equal to the debt service due from the counties on the related pollution control bonds. Depending on the type of expense, the Successor capitalized debt expenses in long-term other regulatory assets or long-term other assets to align with the term of the debt for which the

expenses were related. The Predecessor capitalized debt expenses in current or long-term other regulatory assets or other current or long-term other assets based on the amount of expense expected to be recovered within the next year through rate recovery. Both Predecessor and Successor amortized debt expenses over the lives of the related bond issues. The Predecessor presentation and the Successor presentation are both appropriate under regulatory practices and GAAP.

In October 2010, in order to secure their respective obligations with respect to the pollution control bonds, KU issued first mortgage bonds to the pollution control bond trustees. KU's first mortgage bonds contain terms and conditions that are substantially parallel to the terms and conditions of the counties' debt, but provide that obligations are deemed satisfied to the extent of payments under the related loan agreement, and thus generally require no separate payment of principal and interest except under certain circumstances, including should KU default on the respective loan agreement. Also in October 2010, one national rating agency revised downward the short-term credit rating of the pollution control bonds and the Company's issuer rating as a result of the pending acquisition by PPL.

Several series of KU's pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At December 31, 2010, KU had an aggregate $351 million of outstanding pollution control indebtedness, of which $96 million is in the form of insured auction rate securities wherein interest rates are reset every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. Since 2008, interest rates increased and the Company experienced "failed auctions" when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture.

The average annualized interest rates on the auction rate bonds follow:

Successor	Predecessor	
November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	December 31, 2009
0.53%	0.51%	0.44%

The instruments governing this auction rate bond permit KU to convert the bond to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently.

As a result of downgrades of the monoline insurers by all of the rating agencies to levels below that of the Company's rating, the debt ratings of the Company's insured bonds are all based on the Company's senior secured debt rating and are not influenced by the monoline bond insurer ratings.

In connection with the PPL acquisition, on November 1, 2010, KU borrowed $1,331 million from a PPL subsidiary, in order to repay loans from a subsidiary of E.ON. KU used the net proceeds received from the sale of the first mortgage bonds to repay the debt owed to the PPL subsidiary arising from the borrowing.

In November 2010, KU issued first mortgage bonds totaling $1,500 million and used the proceeds to repay the loans from a PPL subsidiary mentioned above and for general corporate purposes. The first mortgage bonds were issued at a discount as described in the table below:

First Mortgage Bonds	Principal	Discount Price	First Mortgage Bonds Proceeds (a)
Series due 2015	$ 250	99.650%	$ 249
Series due 2020	500	99.622%	498
Series due 2040	750	98.915%	742
Total	$ 1,500		$ 1,489

(a) Before expenses other than discount to Purchaser

The first mortgage bonds were issued by KU in accordance with the rules of Section 144A of the Securities Act of 1933. KU has entered into a registration rights agreement in which it has agreed to file a registration statement with the SEC relating to an offer to exchange the first mortgage bonds for publicly tradable securities having substantially identical terms. If ultimate registration and/or certain milestones are not completed by certain dates in mid- and late 2011, the Company has agreed to pay liquidated damages to the bondholders. The liquidated damages would total 0.25% per annum of the principal amount of the bonds for the first 90 days and 0.50% per annum of the principal amount thereafter until the conditions described above have been cured.

There were no redemptions or maturities of long-term debt for 2009. Redemptions and maturities of long-term debt for 2010 are summarized below:

Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
Successor					
2010	Due to PPL Investment Corp.	$ 1,331	4.24%-7.035%	Unsecured	2010-2037
2010	Due to E.ON affiliates	1,331	4.24%-7.035%	Unsecured	2010-2037

Issuances of long-term debt for 2010 and 2009 are summarized below:

Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
Successor					
2010	Due to PPL Investment Corp.	$ 1,331	4.24%-7.035%	Unsecured	2010-2037
2010	First mortgage bonds	250	1.625%	Secured	2015
2010	First mortgage bonds	500	3.25%	Secured	2020
2010	First mortgage bonds	750	5.125%	Secured	2040
Predecessor					
2009	Due to E.ON affiliates	50	4.445%	Unsecured	2019
2009	Due to E.ON affiliates	50	4.81%	Unsecured	2019
2009	Due to E.ON affiliates	50	5.28%	Unsecured	2017

As of December 31, 2010, all of the Company's long-term debt is secured by a first mortgage lien on substantially all of the real and tangible personal property of the Company located in Kentucky.

Long-term debt maturities for KU are shown in the following table:

2011	$ -
2012	-
2013	-
2014	-
2015	250
Thereafter	1,601
	$ 1,851

KU was in compliance with all debt covenants at December 31, 2010.

See Note 1, Summary of Significant Accounting Policies, for certain debt refinancing and associated transactions completed by KU in connection with the PPL acquisition, Note 2, Acquisition by PPL, for the adjustment made to the pollution control bonds to reflect fair value and Note 15, Related Party Transactions, for long-term debt payable to affiliates.

Note 12 - Notes Payable and Other Short-Term Obligations

Intercompany Revolving Line of Credit

KU participates in an intercompany money pool agreement wherein LKE and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) of up to $400 million. Details of the balances are as follows:

	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2010, Successor	$ 400	$ 10	$ 390	0.25%
December 31, 2009, Predecessor	400	45	355	0.20%

LKE maintains revolving credit facilities totaling $300 million at December 31, 2010 and $313 million at December 31, 2009, to ensure funding availability for the money pool. At December 31, 2010, the LKE facility is with PPL Investment Corp. LKE pays PPL Investment Corp. an annual commitment fee based on the Utilities' current bond ratings on the unused portion of the commitment. At December 31, 2009, one facility, totaling $150 million, was with E.ON North America, Inc., while the remaining line, totaling $163 million, was with Fidelia, both affiliated companies of E.ON. The balances are as follows:

	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2010, Successor	$ 300	$ -	$ 300	N/A
December 31, 2009, Predecessor	313	276	37	1.25%

Bank Revolving Line of Credit

As of December 31, 2010, the Company maintained a $400 million revolving line of credit with a group of banks maturing in December 2014. The revolving line of credit allows KU to issue letters of credit or borrow funds up to $400 million. Outstanding letters of credit reduce the facility's available borrowing capacity. The Company pays the banks an annual commitment fee based on current bond ratings on the unused portion of the commitment. At December 31, 2010, there was no amount borrowed under this facility although letters of credit totaling $198 million have been issued under this facility. This credit agreement contains financial covenants requiring the borrower's debt to total capitalization ratio to not exceed 70%, as calculated pursuant to the credit agreement, and other customary covenants.

As of December 31, 2009, the Company maintained a $35 million bilateral line of credit with an unaffiliated financial institution maturing in June 2012. The Company paid the banks an annual commitment fee on the unused portion of the commitment. At December 31, 2009, there was no balance outstanding under this facility. This facility was terminated on November 1, 2010, in conjunction with the PPL acquisition.

On December 1, 2010, KU replaced the letters of credit issued under prior letter of credit facilities with letters of credit of the same amount issued under the revolving line of credit. The four letter of credit facilities were subsequently terminated.

KU was in compliance with all line of credit covenants at December 31, 2010.

See Note 1, Summary of Significant Accounting Policies, for certain debt refinancing and associated transactions completed by KU in connection with the PPL acquisition and Note 15, Related Party Transactions, for long-term debt payable to affiliates.

Note 13 - Commitments and Contingencies

Operating Leases

KU leases office space, office equipment, plant equipment, real estate, railcars, telecommunications and vehicles and accounts for these leases as operating leases. In addition, KU reimburses LG&E for a portion of the lease expense paid by LG&E for KU's usage of office space leased by LG&E. Total lease expense was $10 million, $10 million and $9 million for 2010, 2009 and 2008, respectively. The future minimum annual lease payments for operating leases for years subsequent to December 31, 2010, are shown in the following table:

2011	$	8
2012		7
2013		5
2014		5
2015		3
Thereafter		1
	$	29

Owensboro Contract Litigation and Termination

In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. In May 2009, KU and OMU executed a settlement agreement resolving the matter on a basis consistent with prior court rulings and KU has received the agreed settlement amounts. Pursuant to the settlement's operation, the OMU Agreement terminated in May 2010.

Sale and Leaseback Transaction

The Company is a participant in a sale and leaseback transaction involving its 62% interest in two jointly owned CTs at KU's E.W. Brown generating station (Units 6 and 7). Commencing in December 1999, KU and LG&E entered into a tax-efficient, 18-year lease of the CTs. The Utilities have provided funds to fully defease the lease and have executed an irrevocable notice to exercise an early purchase option contained in the lease after 15.5 years. The financial statement treatment of this transaction is no different than if the Utilities had retained its ownership interest. The leasing transaction was entered into following receipt of required state and federal regulatory approvals. At December 31, 2010, the Balance Sheets included these assets at a value of $65 million, which is reflected in "Regulated utility plant – electric."

In case of default under the lease, the Company is obligated to pay to the lessor its share of certain fees or amounts. Primary events of default include loss or destruction of the CTs, failure to insure or maintain the CTs and unwinding of the transaction due to governmental actions. No events of default currently exist with respect to the lease. Upon any termination of the lease, whether by default or expiration of its term, title to the CTs reverts jointly to KU and LG&E.

At December 31, 2010, the maximum aggregate amount of default fees or amounts was $7 million, of which KU would be responsible for 62% (approximately $4 million). The Company has made arrangements with LKE, via guarantee and regulatory commitment, for LKE to pay its full portion of any default fees or amounts.

Letters of Credit

KU has provided letters of credit as of December 31, 2010 and 2009, for on-balance sheet obligations totaling $198 million to support bonds of $195 million and letters of credit for off-balance sheet obligations totaling less than $1 million to support certain obligations related to workers' compensation.

Commodity Purchases

OVEC

KU has a contract for power purchases with OVEC, terminating in 2026, for various Mw capacities. KU holds a 2.5% investment interest in OVEC with ten other electric utilities. KU is not the primary beneficiary; therefore, the investment is not consolidated into the Company's financial statements, but is recorded on the cost basis. OVEC is located in Piketon, Ohio, and owns and operates two coal-fired power plants, Kyger Creek Station in Ohio, and Clifty Creek Station in Indiana. KU is contractually entitled to 2.5% of OVEC's output, approximately 60 Mw of nameplate generation capacity. Pursuant to

the OVEC power purchase contract, the Company may be conditionally responsible for a 2.5% pro-rata share of certain obligations of OVEC under defined circumstances. These contingent liabilities may include unpaid OVEC indebtedness as well as shortfall amounts in certain excess decommissioning costs and postretirement benefits other than pension. KU's contingent potential proportionate share of OVEC's December 31, 2010 outstanding debt was $35 million. Future obligations for power purchases from OVEC are demand payments, comprised of annual minimum debt service payments, as well as contractually required reimbursement of plant operating, maintenance and other expenses, and are shown in the following table:

2011	$ 9
2012	10
2013	10
2014	10
2015	10
Thereafter	114
	$ 163

Coal and Natural Gas Transportation Purchase Obligations

KU has contracts to purchase coal and natural gas transportation. Future obligations are shown in the following table:

2011	$ 439
2012	200
2013	144
2014	93
2015	91
Thereafter	14
	$ 981

Construction Program

KU had approximately $116 million of commitments in connection with its construction program at December 31, 2010.

In June 2006, KU entered into a construction contract regarding the TC2 project. The contract is generally in the form of a turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price. During 2009 and 2010, KU received several contractual notices from the TC2 construction contractor asserting historical force majeure and excusable event claims for a number of adjustments to the contract price, construction schedule, commercial operations date, liquidated damages or other relevant provisions. In September 2010, KU and the construction contractor agreed to a settlement to resolve the force majeure and excusable event claims occurring through July 2010, under the TC2 construction contract, which settlement provided for a limited, negotiated extension of the contractual commercial operations date and/or relief from liquidated damage calculations. With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand

since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. KU cannot currently estimate the ultimate outcome of these matters.

<u>TC2 Air Permit</u>

The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the KDAQ in November 2005. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an Order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the two EPA objections. In March 2010, the Sierra Club submitted a petition to the EPA to object to the permit revision, which is now pending before the EPA. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the EPA issues a final ruling on the pending petition and all applicable appeals have been exhausted, the Company cannot predict the final outcome of this matter.

<u>Environmental Matters</u>

The Company's operations are subject to a number of environmental laws and regulations in each of the jurisdictions in which it operates governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety. As indicated below and summarized at the conclusion of this section, evolving environmental regulations will likely increase the level of capital and operating and maintenance expenditures incurred by the Company during the next several years. Based upon prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

Ambient Air Quality

The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS

through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which required additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provided for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR.

In July 2008, a federal appeals court issued a ruling finding deficiencies in the CAIR and vacating it. In December 2008, the Court amended its previous Order, directing the EPA to promulgate a new regulation but leaving the CAIR in place in the interim. The remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and the Utilities' compliance plans relating thereto due to the interconnection of the CAIR with such associated programs.

In January 2010, the EPA proposed a revised NAAQS for ozone which would increase the stringency of the standard. In addition, the EPA published final revised NAAQS standards for NO_2 and SO_2 in February 2010 and June 2010, respectively, which are more stringent than previous standards. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the revised NAAQS standards, KU's power plants are potentially subject to requirements for additional reductions in SO_2 and NOx emissions.

In July 2010, the EPA issued the proposed CATR, which serves to replace the CAIR. The CATR provides for a two-phase SO_2 reduction program with Phase I reductions due by 2012 and Phase II reductions due by 2014. The CATR provides for NOx reductions in 2012, but the EPA advised that it is studying whether additional NOx reductions should be required for 2014. The CATR is more stringent than the CAIR as it accelerates certain compliance dates and provides for only intrastate and limited interstate trading of emission allowances. In addition to its preferred approach, the EPA is seeking comment on an alternative approach which would provide for individual emission limits at each power plant. The EPA has announced that it will propose additional "transport" rules to address compliance with revised NAAQS standards for ozone and particulate matter which will be issued by the EPA in the future, as discussed below.

Hazardous Air Pollutants

As provided in the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provided for reductions of

70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The EPA has entered into a consent decree requiring it to promulgate a utility Maximum Achievable Control Technology rule to replace the CAMR with a proposed rule due by March 2011 and a final rule by November 2011. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new rules with different or more stringent requirements for reduction of mercury and other hazardous air pollutants. Kentucky has also repealed its corresponding state mercury regulations.

Acid Rain Program

The Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The Clean Air Act also contains requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze

The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its Clean Air Visibility Rule detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR provided for more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPs incorporate certain CAIR requirements, the remand of the CAIR could potentially impact regional haze SIPs. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls

Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. KU met its Phase I SO_2 requirements primarily through installation of FGD equipment on Ghent Unit 1. KU's strategy for its Phase II SO_2 requirements, which commenced in 2000, includes the installation of additional FGD equipment, as well as using accumulated emission allowances and fuel switching to defer certain additional capital expenditures and continue to evaluate improvements to further reduce SO_2 emissions. KU believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. KU's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. KU will

continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. KU expects to incur additional capital expenditures currently approved in its ECR plans totaling approximately $500 million during the 2011 through 2013 time period to achieve emissions reductions and manage coal combustion residuals. Monthly recovery is subject to periodic review by the Kentucky Commission.

GHG Developments

In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. As discussed below, legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs, including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are on-going. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark, in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. In Copenhagen, the U.S. made a nonbinding commitment to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations met in Cancun, Mexico, in December 2010 to continue negotiations toward a binding agreement.

GHG Legislation

KU is monitoring on-going efforts to enact GHG reduction requirements and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, which was a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. The bill provided for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020 and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would have initially been allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would have also established a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contained additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency.

In September 2009, the Clean Energy Jobs and American Power Act, which was largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raised the emissions reduction target for 2020 to 20% below 2005 levels and did not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision incorporated allowance allocation provisions similar to the House bill. Although Senators Kerry and Lieberman and others worked to reach a consensus on GHG legislation, no bill passed the Senate in 2010. The Company is closely monitoring the progress of pending energy legislation, but the prospect for passage of comprehensive GHG legislation in 2011 is uncertain.

GHG Regulations

In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. In April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities are required to submit annual reports commencing with calendar year 2010. In May 2010, the EPA issued a final GHG "tailoring" rule, effective January 2011, requiring new or modified sources with GHG emissions equivalent to at least 75,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the rule. The final rule will apply to new and modified power plants beginning in January 2011. The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations. In December 2010, the EPA announced that it plans to promulgate GHG New Source Performance Standards for power plants, including both new and existing facilities. A proposed rule is expected by July 2011, while a final rule is expected by May 2012. In the absence of either a proposed or final regulation, KU is unable to assess the potential impact of any future regulation.

GHG Litigation

A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, a three judge panel of the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. In March 2010, the court vacated the opinion of the three-judge panel and granted a motion for rehearing but subsequently denied the appeal due to the lack of a quorum. The appellate ruling leaves in effect the lower court ruling dismissing the plaintiffs' claims. In January 2011, the Supreme Court denied petitioner's petition for review, which effectively brings the case to an end. The Comer complaint alleged that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. E.ON, the former indirect parent of the Utilities, was named as a defendant in the complaint but was not a party to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. KU continues to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to operations.

Ghent Opacity NOV

In September 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July of 2007 at Units 1 and 3 of KU's Ghent generating station. The parties have met on this matter and KU has received no further communications from the EPA. The Company is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

Ghent New Source Review NOV

In March 2009, the EPA issued an NOV alleging that KU violated certain provisions of the Clean Air Act's rules governing new source review and prevention of significant deterioration by installing FGD and SCR controls at its Ghent generating station without assessing potential increased sulfuric acid mist emissions. KU contends that the work in question, as pollution control projects, was exempt from the requirements cited by the EPA. In December 2009, the EPA issued a Section 114 information request seeking additional information on this matter. In March 2010, the Company received an EPA settlement proposal providing for imposition of additional permit limits and emission controls and anticipates continued settlement negotiations with the EPA. Negotiations between the EPA and KU are ongoing. Depending on the provisions of a final settlement or the results of litigation, if any, resolution of this matter could involve significant increased operating and capital expenditures. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination on the Company's financial position or results of operations.

Ash Ponds and Coal-Combustion Byproducts

The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the TVA's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including KU, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of KU's impoundments, which the EPA found to be in satisfactory condition. In June 2010, the EPA published proposed regulations for coal combustion byproducts handled in landfills and ash ponds. The EPA has proposed two alternatives: (1) regulation of coal combustion byproducts in landfills and ash ponds as a hazardous waste or (2) regulation of coal combustion byproducts as a solid waste with minimum national standards. Under both alternatives, the EPA has proposed safety requirements to address the structural integrity of ash ponds. In addition, the EPA will consider potential refinements of the provisions for beneficial reuse of coal combustion byproducts.

Water Discharges and PCB Regulations

The EPA has also announced plans to develop revised effluent limitation guidelines governing discharges from power plants and standards for cooling water intake structures. The EPA has further announced plans to develop revised standards governing the use of polychlorinated biphenyls ("PCB") in electrical equipment. The Company is monitoring these ongoing regulatory developments but will be unable to determine the impact until such time as new rules are finalized.

Impact of Pending and Future Environmental Developments

As a company with significant coal-fired generating assets, KU will likely be substantially impacted by pending or future environmental rules or legislation requiring mandatory reductions in GHG emissions or other air emissions, imposing more stringent standards on discharges to waterways, or establishing additional requirements for handling or disposal of coal combustion byproducts. These evolving environmental regulations will likely require an increased level of capital expenditures and increased incremental operating and maintenance costs by the Company over the next several years. Due to the uncertain nature of the final regulations that will ultimately be adopted by the EPA, including the

reduction targets and the deadlines that will be applicable, the Company cannot finalize estimates of the potential compliance costs, but should the final rules incorporate additional emission reduction requirements, require more stringent emissions controls or implement more stringent byproducts storage and disposal practices, such costs will likely be significant. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based upon a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Capital expenditures for KU associated with such actions are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary. With respect to potential developments in water discharge, revised PCB standards or GHG initiatives, costs in such areas cannot be estimated due to the preliminary status or uncertain outcome of such developments, but would be in addition to the above amount and could be substantial. Ultimately, the precise impact on the Company's operations of these various environmental developments cannot be determined prior to the finalization of such requirements. Based upon prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

TC2 Water Permit

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County generating station. In October 2010, the hearing officer issued a report and recommended Order providing for dismissal of the claims raised by the petitioners. In December 2010, the Secretary issued a final Order dismissing all claims and upholding the permit which petitioners subsequently appealed to Trimble County Circuit Court.

General Environmental Proceedings

From time to time, KU appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include a prior Section 114 information request from the EPA relating to new-source review issues at KU's Ghent unit 2; completed settlement with state regulators regarding compliance with particulate limits in the air permit for KU's Tyrone generating station; remediation obligations or activities for or other risks relating to elevated PCB levels at existing properties; liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites; and on-going claims regarding the GHG emissions from the Company's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the Company's operations.

Note 14 - Jointly Owned Electric Utility Plant

TC2 is a jointly owned unit at the Trimble County site. KU and LG&E own undivided 60.75% and 14.25% interests, respectively. Of the remaining 25%, IMEA owns a 12.12% undivided interest and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate share of capital cost during construction and fuel, operation and maintenance cost when TC2 is in-service. With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. In December 2009 and June 2008, LG&E sold assets to KU related to the construction of TC2 with a net book value of $48 million and $10 million, respectively.

The following data represent shares of the jointly owned property (capacity based on nameplate rating):

	TC2				
	KU	LG&E	IMPA	IMEA	Total
Ownership interest	60.75%	14.25%	12.88%	12.12%	100%
Mw capacity	509	119	108	102	838

KU's 60.75% ownership:		LG&E's 14.25% ownership:	
Plant held for future use	$ 62	Plant held for future use	$ 2
Construction work in progress	703	Construction work in progress	187
Accumulated depreciation	(1)	Accumulated depreciation	-
Net book value	$ 764	Net book value	$ 189

KU and LG&E jointly own the following CTs and related equipment (capacity based on net summer capability) as of December 31, 2010:

	KU				LG&E				Total			
Ownership Percentage	Mw Capacity	Cost	Depr.	Net Book Value	Mw Capacity	Cost	Depr.	Net Book Value	Mw Capacity	Cost	Depr.	Net Book Value
KU 47%, LG&E 53% (a)	129	$ 43	$ -	$ 43	146	$ 48	$ -	$ 48	275	$ 91	$ -	$ 91
KU 62%, LG&E 38% (b)	190	64	(2)	62	118	40	(2)	38	308	104	(4)	100
KU 71%, LG&E 29% (c)	228	63	(1)	62	92	26	-	26	320	89	(1)	88
KU 63%, LG&E 37% (d)	404	109	(1)	108	236	64	(1)	63	640	173	(2)	171
KU 71%, LG&E 29% (e)	n/a	4	-	4	n/a	2	-	2	n/a	6	-	6

(a) Comprised of Paddy's Run 13 and E.W. Brown 5. In addition to the above jointly owned utility plant, there is an inlet air cooling system attributable to unit 5 and units 8-11 at the E.W. Brown facility. This inlet air cooling system is not jointly owned, however, it is used to increase production on the units to which it relates, resulting in an additional 88 Mw of capacity for KU.

(b) Comprised of units 6 and 7 at the E.W. Brown facility.
(c) Comprised of units 5 and 6 at the Trimble County facility.
(d) Comprised of CT Substation 7-10 and units 7, 8, 9 and 10 at the Trimble County facility.
(e) Comprised of CT Substation 5 and 6 and CT Pipeline at the Trimble County facility.

Both KU's and LG&E's participating share of direct expenses of the jointly owned plants is included in the corresponding operating expenses on each company's respective Statements of Income (i.e., fuel, maintenance of plant, other operating expense).

Note 15 - Related Party Transactions

KU and subsidiaries of LKE and PPL engage in related party transactions. Transactions between KU and LKE subsidiaries are eliminated on consolidation of LKE. Transactions between KU and PPL subsidiaries are eliminated on consolidation of PPL. These transactions are generally performed at cost and are in accordance with FERC regulations under PUHCA 2005 and the applicable Kentucky Commission and Virginia Commission regulations.

Intercompany Wholesale Sales and Purchases

KU and LG&E jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are recorded as intercompany wholesale sales and purchases are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the Utilities. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

These sales and purchases are included in the Statements of Income as "Operating revenues", "Power purchased" expenses and "Other operation and maintenance expenses". KU's intercompany electric revenues and power purchased expenses were as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Electric operating revenues from LG&E	$ 2	$ 13	$ 21	$ 80
Power purchased and related operations and maintenance expenses from LG&E	21	79	101	109

Interest Charges

See Note 11, Long-Term Debt, and Note 12, Notes Payable and Other Short-Term Obligations, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

KU's interest expense to affiliated companies was as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Interest on money pool loans	$ -	$ -	$ -	$ 2
Interest on PPL loans	2	-	-	-
Interest on Fidelia loans	-	62	69	56

Interest paid to LKE on the money pool arrangement was less than $1 million for 2010 and 2009.

Dividends

In September 2010, the Company paid dividends of $50 million to its sole shareholder, LKE.

Capital Contributions

The Company received no capital contributions in 2010, but received capital contributions of $75 million and $145 million from its sole shareholder, LKE, in 2009 and 2008, respectively.

Sale of Assets

In 2010, KU sold and bought assets of less than $1 million to and from LG&E. In December 2009, LG&E sold assets to KU related to the construction of TC2 with a net book value of $48 million.

Other Intercompany Billings

Servco provides the Company with a variety of centralized administrative, management and support services. Associated charges include payroll taxes paid by Servco on behalf of KU, labor and burdens of Servco employees performing services for KU, coal purchases and other vouchers paid by Servco on behalf of KU. The cost of these services is directly charged to the Company, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and/or other statistical information. These costs are charged on an actual cost basis.

In addition, the Utilities provide services to each other and to Servco. Billings between the Utilities relate to labor and overheads associated with union and hourly employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from KU to Servco include cash received by Servco on behalf of KU, tax settlements and other payments

made by the Company on behalf of other non-regulated businesses which are reimbursed through Servco.

Intercompany billings to and from KU were as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Servco billings to KU	$ 46	$ 233	$ 169	$ 227
LG&E billings to KU	14	49	44	5
KU billings to Servco	12	11	14	3
KU billings to LG&E	-	-	78	75

Intercompany Balances

The Company had the following balances with its affiliates:

	Successor December 31, 2010	Predecessor December 31, 2009
Accounts receivable from LKE	$ 12	$ 9
Accounts payable to LG&E	22	53
Accounts payable to Servco	23	20
Accounts payable to Fidelia	-	15
Notes payable to LKE	10	45
Long-term debt to Fidelia	-	1,331

Note 16 - Selected Quarterly Data (Unaudited)

	For the 2010 Periods Ended (a)				
	Predecessor				Successor
	March 31	June 30	September 30	October 31	December 31
Operating revenues	$ 380	$ 350	$ 416	$ 102	$ 263
Operating income	87	71	105	22	65
Net income	44	31	54	11	35

(a) Periods ended March 31, June 30 and September 30 represent three months then ended. Period ended October 31 represents one month then ended and period ended December 31 represents two months then ended.

	For the 2009 Quarters Ended			
	Predecessor			
	March 31	June 30	September 30	December 31
Operating revenues	$ 363	$ 305	$ 341	$ 346
Operating income	19	53	125	72
Net income	7	26	66	34

Note 17 - Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consisted of the following:

	Pre-Tax Accumulated Derivative Gain (Loss)	Income Taxes	Net
Balance at December 31, 2009, Predecessor	$ -	$ -	$ -
Equity investee's other comprehensive income (loss)	(3)	1	(2)
Balance at October 31, 2010, Predecessor	(3)	1	(2)
Effect of PPL acquisition	3	(1)	2
Balance at December 31, 2010, Successor	$ -	$ -	$ -

Note 18 - Subsequent Events

Subsequent events have been evaluated through February 25, 2011, the date of issuance of these statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

On January 31, 2011, KU filed a notice of intent to file a rate case with the Virginia Commission for the test year ended December 31, 2010. The case is expected to be filed on or after April 1, 2011.

With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. LG&E and KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages.

On January 14, 2011, KU contributed $43 million to its pension plan.

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Report of Independent Auditors

To Stockholder of Kentucky Utilities Company

In our opinion, the accompanying balance sheet and the related statements of income, retained earnings, comprehensive income, cash flows, and capitalization present fairly, in all material respects, the financial position of Kentucky Utilities Company (Successor Company) at December 31, 2010 and the results of its operations and its cash flows for the period from November 1, 2010 to December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assertion of the effectiveness of internal control over financial reporting, included in "Management's Report of Internal Controls Over Financial Reporting" which appears on page 50. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audit. We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States) and in accordance with the auditing and attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

As discussed in Note 2 to the financial statements, on November 1, 2010, PPL Corporation completed its acquisition of LG&E and KU Energy LLC and its subsidiaries. The push-down basis of accounting was used at the acquisition date.

A company's internal control over financial reporting is a process effected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial

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statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and those charged with governance and (iii) provide reasonable assurance regarding prevention or timely detection and correction of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect and correct misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Louisville, Kentucky
February 25, 2011

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Report of Independent Auditors

To Stockholder of Kentucky Utilities Company

In our opinion, the accompanying balance sheet and the related statements of income, retained earnings, comprehensive income, cash flows, and capitalization present fairly, in all material respects, the financial position of Kentucky Utilities Company (Predecessor Company) at December 31, 2009 and the results of its operations and its cash flows for the period from January 1, 2010 to October 31, 2010 and for each of the two years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the financial statements, on November 1, 2010, PPL Corporation completed its acquisition of LG&E and KU Energy LLC and its subsidiaries. The push-down basis of accounting was used at the acquisition date.

PricewaterhouseCoopers LLP

Louisville, Kentucky
February 25, 2011

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Supplement, dated December 1, 2010 to Reoffering Circular dated December 11, 2008, as supplemented as of December 16, 2008 and October 29, 2010 (the "Reoffering Circular")

$54,000,000 **County of Carroll, Kentucky** **Environmental Facilities Revenue** **Refunding Bonds, 2006 Series B** **(Kentucky Utilities Company Project)**	**$77,947,405** **County of Carroll, Kentucky** **Environmental Facilities Revenue** **Bonds,** **2008 Series A** **(Kentucky Utilities Company Project)**

Effective as of December 1, 2010, through December 1, 2011 (the Letter of Credit (as defined below) expiration date, subject to extension or earlier termination), payment of the principal of and interest on each series of the above-referenced bonds (individually, the "2006 Series B Bonds" and the "2008 Series A Bonds" and, collectively, the "Bonds") when due will be paid with funds drawn under an irrevocable transferable direct pay letter of credit (the "Letter of Credit") issued by

WELLS FARGO BANK, NATIONAL ASSOCIATION

The Letter of Credit will permit the Trustee to draw with respect to each series of Bonds up to an amount sufficient to pay (i) the principal of such series of Bonds (or that portion of the purchase price corresponding to principal) plus (ii) interest thereon (or that portion of the purchase price corresponding to interest) at an assumed rate of 15% per annum for at least 45 days.

Each series of Bonds will continue to bear interest at a Weekly Rate, determined by the Remarketing Agent in accordance with the Indenture, payable on the first Business Day of each calendar month, commencing on January 3, 2011. The interest rate period, interest rate and Interest Rate Mode for each series of Bonds will be subject to change under certain conditions, as described in the Reoffering Circular. The Bonds of each series are subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption following a determination of taxability prior to maturity, as described in the Reoffering Circular. The Bonds of each series are subject to mandatory purchase on any date on which the Bonds are converted to a different Interest Rate Mode and upon the expiration of the Letter of Credit or any Alternate Credit Facility.

This supplement contains a description of the Letter of Credit and Wells Fargo Bank, National Association, the issuer of the Letter of Credit. For purposes of the Reoffering Circular, the Letter of Credit is a "Credit Facility" and Wells Fargo Bank, National Association is a "Credit Facility Issuer." Except as otherwise specified herein, information in the Reoffering Circular referred to above has not been amended or modified and the information contained herein is qualified by reference to, and should be read in conjunction with, the Reoffering Circular, including information incorporated therein by reference. Terms not otherwise defined herein shall have the meanings ascribed to them in such Reoffering Circular.

The eighth paragraph under the section of the Reoffering Circular captioned "Introductory Statement" is hereby amended to read in its entirety as follows:

Effective December 1, 2010, the Company will cause to be delivered separate irrevocable transferable direct pay letters of credit (the "Letters of Credit") with respect to each of the 2006 Series B Bonds and the 2008 Series A Bonds, issued by Wells Fargo Bank, National Association (the "Bank"), to provide for the timely payment of principal of and accrued interest (calculated for at least 45 days at the maximum rate of 15% per annum) on, and purchase price of, the Bonds. The Company will be required to reimburse the Bank for all amounts drawn by the Trustee under the Letters of Credit pursuant to the terms of separate letter agreements, to be dated as of December 1, 2010 (collectively, the "Reimbursement Agreement"), with respect to each of the 2006 Series B Bonds and the 2008 Series A Bonds, between the Company and the Bank. Each Letter of Credit will expire on December 1, 2011 unless extended or earlier terminated.

***   *   *   ***

The section of the Reoffering Circular captioned "The Letter of Credit" is hereby amended to read in its entirety as follows:

THE LETTER OF CREDIT

The following summarizes certain provisions of the Letter of Credit and the Reimbursement Agreement, to which reference is made for the detailed provisions thereof. Unless otherwise defined in this Reoffering Circular, capitalized terms in the following summary are used as defined in the Letter of Credit and the Reimbursement Agreement. The Company is permitted under the Indenture to deliver an Alternate Credit Facility to replace the Letter of Credit. Any such Alternate Credit Facility must meet certain requirements described in the Indenture.

The Letter of Credit

The Letter of Credit will be an irrevocable transferable direct pay letter of credit issued by the Bank in order to provide additional security for the payment of principal of, purchase price of, interest on and premium, if applicable, on any date when payments under the Bonds are due, including principal and interest payments and payments upon tender, redemption, acceleration or maturity of the Bonds. The Letter of Credit will provide for direct payments to or upon the order of the Trustee as set forth in the Letter of Credit in amounts sufficient to pay such amounts in accordance with the terms thereof.

The Letter of Credit will be issued in an amount equal to the aggregate principal amount of the outstanding Bonds, plus an amount that represents interest accrued thereon at an assumed rate of 15% per annum for 45 days (the "Credit Amount"). The Trustee, upon compliance with the terms of the Letter of Credit, is authorized to draw up to (a) an amount sufficient (i) to pay principal of the Bonds, when due, whether at maturity or upon redemption or acceleration, and (ii) to pay the portion of the purchase price of the Bonds delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed (a "Liquidity Drawing") equal to the principal amount of the Bonds, plus (b) an amount not to exceed 45 days of accrued interest on such Bonds at an assumed rate of 15% per annum (i) to pay interest on the Bonds, when due, and (ii) to pay the portion of the interest accrued on the Bonds as of any Liquidity Drawing.

The amount available under the Letter of Credit will be automatically reduced by the amount of any drawing thereunder, subject to reinstatement as described below. With respect to a drawing by the Trustee solely to pay interest on the Bonds on an Interest Payment Date, the amount available under the Letter of Credit will be automatically reinstated in the amount of such drawing effective on the earlier of (i) receipt by the Bank from the Company of reimbursement of any drawing solely to pay interest in full or (ii) at the opening of business on the eleventh calendar day after the date the Bank honors such drawing, unless the Trustee has received written notice from the Bank by the tenth calendar day after the date the Bank honors such drawing the Bank is not so reinstating the available amount due to the Company's failure to reimburse the Bank for such drawing in full, or that an event of default has occurred and is continuing under the Reimbursement Agreement and, in either case, directing, an acceleration of the Bonds pursuant to the Indenture. With respect to a Liquidity Drawing under the Letter of Credit, the amount available under the Letter of Credit will be automatically reduced by the principal amount of the Bonds purchased with the proceeds of such drawing plus the amount of accrued interest on such Bonds. In the event of the remarketing of the Bonds purchased with the proceeds of a Liquidity Drawing, the amount available under the Letter of Credit will be automatically reinstated upon receipt by the Bank or the Trustee on the Bank's behalf of an amount equal to such principal amount plus accrued interest.

The Letter of Credit will terminate on the earliest to occur of:

(i) the Bank's close of business on December 1, 2011 (such date, as extended from time to time in accordance with the Letter of Credit is defined as the "Stated Expiration Date");

(ii) the Bank's close of business on the date which is five Business Days following the date of receipt by the Bank of a certificate from the Trustee certifying that (a) no Bonds remain Outstanding within the meaning of the Indenture, (b) all drawings required to be made under the Indenture and available under the Letter of Credit have been made and honored, (c) an Alternate Credit Facility has been delivered to the Trustee in accordance with the Indenture to replace the Letter of Credit or (d) all of the outstanding Bonds were converted to Bonds bearing interest at a rate other than the Daily Rate or the Weekly Rate;

(iii) the Bank's close of business on the date of receipt by the Bank of a certificate from the Trustee confirming that the Trustee is required to terminate the Letter of Credit in accordance with the terms of the Indenture;

(iv) the date on which the Bank receives and honors an acceleration drawing certificate; or

(v) the Bank's close of business on the date which is 30 days after receipt by the Trustee of written notice from the Bank of an Event of Default under the $400,000,000 Revolving Credit Agreement dated as of November 1, 2010 among the Company, the lending institutions party thereto from time to time and Wells Fargo Bank, National Association, as Administrative Agent (the "Credit Agreement") and instructing the Trustee to draw under the Letter of Credit.

The Reimbursement Agreement

Pursuant to the Reimbursement Agreement, the Company is obligated to reimburse the Bank for all amounts drawn under the Letter of Credit, and to pay interest on all such amounts. The Company has also agreed to pay the Bank a periodic fee for issuing and maintaining the Letter of Credit.

The Reimbursement Agreement, through incorporation of the terms of the Credit Agreement, imposes various covenants and agreements, including various financial and operating covenants, on the Company. Such covenants include, but are not limited to, covenants relating to (i) inspection of the books and financial records of the Company; (ii) mergers or consolidations; and (iii) disposition of assets. Any such covenants may be amended, waived or modified at any time by the Bank and without the consent of the Trustee or the holders of the Bonds. Under certain circumstances, the failure of the Company to comply with such covenants may result in a mandatory tender or acceleration of the Bonds.

An Event of Default under the Credit Agreement will constitute an Event of Default under the Reimbursement Agreement. The following events will constitute an Event of Default under the Credit Agreement:

(i) the Borrower shall fail to pay when due any principal on any Loans under the Credit Agreement or Reimbursement Obligations; or

(ii) the Company shall fail to pay when due any interest on the Loans under the Credit Agreement and Reimbursement Obligations, any fee or any other amount payable hereunder or under any other Loan Document for five (5) days following the date such payment becomes due thereunder; or

(iii) the Company shall fail to observe or perform certain covenants or agreements contained in the Credit Agreement, including those related to mergers, disposition of assets and capitalization ratios; or

(iv) the Company shall fail to give notice of a Default or Event of Default under the Credit Agreement within a specified number of days following knowledge of such occurrence; or

(v) the Company shall fail to observe or perform any covenant or agreement contained in the Credit Agreement or any notes issued thereunder (other than those covered above) for thirty (30) days after written notice thereof has been given to the defaulting party by the administrative agent, or at the request of the required lenders; or

(vi) any representation, warranty or certification made by the Company in the Credit Agreement or any notes issued thereunder or in any certificate, financial statement or other document delivered pursuant hereto or thereto shall prove to have been incorrect in any material respect when made or deemed made; or

(vii) the Company shall (i) fail to pay any principal or interest, regardless of amount, due in respect of any Material Debt beyond any period of grace provided with respect thereto, or (ii) fail to observe or perform any other term, covenant, condition or agreement contained in any agreement or instrument evidencing or governing any such Material Debt beyond any period of grace provided with respect thereto if the effect of any failure referred to in this clause (ii) is to cause, or to permit the holder or holders of such Debt or a trustee on its or their behalf to cause, such Debt to become due prior to its stated maturity; or

(viii) the Company shall commence a voluntary case or other proceeding seeking liquidation, reorganization or other relief with respect to itself or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any substantial part of its property, or shall consent to any such relief or to the appointment of or taking possession by any such official in an involuntary case or other proceeding commenced against it, or shall make a general assignment for the benefit of creditors, or shall fail generally to pay, or shall admit in writing its inability to pay, its debts as they become due, or shall take any corporate action to authorize any of the foregoing; or

(ix) an involuntary case or other proceeding shall be commenced against the Company seeking liquidation, reorganization or other relief with respect to it or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any substantial part of its property, and such involuntary case or other proceeding shall remain undismissed and unstayed for a period of 60 days; or an order for relief shall be entered against the Company under the Bankruptcy Code; or

(x) any member of the ERISA Group shall fail to pay when due an amount or amounts aggregating in excess of $50,000,000 which it shall have become liable to pay under Title IV of ERISA; or notice of intent to terminate a Material Plan shall be filed under Title IV of ERISA by any member of the ERISA Group, any plan administrator or any combination of the foregoing; or the PBGC shall institute proceedings under Title IV of ERISA to terminate, to impose liability (other than for premiums under Section 4007 of ERISA) in respect of, or to cause a trustee to be appointed to administer any Material Plan; or a condition shall exist by reason of which the PBGC would be entitled to obtain a decree adjudicating that any Material Plan must be terminated; or there shall occur a complete or partial withdrawal from, or default, within the meaning of Section 4219(c)(5) of ERISA, with respect to, one or more Multiemployer Plans which could reasonably be expected to cause one or more members of the ERISA Group to incur a current payment obligation in excess of $50,000,000; or

(xi) the Company shall fail within sixty (60) days to pay, bond or otherwise discharge any judgment or order for the payment of money in excess of $20,000,000, entered against the Company that is not stayed on appeal or otherwise being appropriately contested in good faith; or

(xii) a Change of Control shall have occurred;

For purposes of the foregoing:

“Change of Control” means (i) the acquisition by any person, or two or more persons acting in concert, of beneficial ownership of 25% or more of the outstanding shares of voting stock of PPL Corporation or its successors or (ii) the failure at any time of PPL Corporation or its successors to own 80% or more of the outstanding shares of the voting stock in the Company.

“Credit Agreement” means the $400,000,000 Revolving Credit Agreement dated as of November 1, 2010 among the Company, the lending institutions party thereto from time to time and Wells Fargo Bank, National Association, as Administrative Agent.

“Material Debt” means debt (other than the notes issued under the Credit Agreement) of the Company in a principal or face amount exceeding $50,000,000

Appendix C of the Reoffering Circular is hereby amended to read in its entirety as follows:

Wells Fargo Bank, National Association

The information under this heading has been provided solely by Wells Fargo Bank, National Association and is believed to be reliable. This information has not been verified independently by the Company, the Issuer or the Remarketing Agent. The Company, the Issuer and the Remarketing Agent make no representation whatsoever as to the accuracy, adequacy or completeness of such information.

Wells Fargo Bank, National Association

Wells Fargo Bank, National Association (the "Bank") is a national banking association organized under the laws of the United States of America with its main office at 101 North Phillips Avenue, Sioux Falls, South Dakota 57104, and engages in retail, commercial and corporate banking, real estate lending and trust and investment services. The Bank is an indirect, wholly owned subsidiary of Wells Fargo & Company, a diversified financial services company, a financial holding company and a bank holding company registered under the Bank Holding Company Act of 1956, as amended, with its principal executive offices located in San Francisco, California.

Each quarter, the Bank files with the FDIC financial reports entitled "Consolidated Reports of Condition and Income for Insured Commercial Banks with Domestic and Foreign Offices," commonly referred to as the "Call Reports." The Bank's Call Reports are prepared in accordance with regulatory accounting principles, which may differ from generally accepted accounting principles. The publicly available portions of Call Reports filed by the Bank with the FDIC may be obtained from the FDIC, Disclosure Group, Room F518, 550 17th Street, N.W., Washington, D.C. 20429 at prescribed rates, or from the FDIC on its Internet site at http://www.fdic.gov, or by writing to Corporate Secretary's Office, Wells Fargo Center, Sixth and Marquette, MAC N9305-173, Minneapolis, MN 55479.

The Letter of Credit will be solely an obligation of the Bank and will not be an obligation of, or otherwise guaranteed by, Wells Fargo & Company, and no assets of Wells Fargo & Company or any affiliate of the Bank or Wells Fargo & Company will be pledged to the payment thereof. Payment of the Letter of Credit will not be insured by the FDIC.

The information contained in this section, including financial information, relates to and has been obtained from the Bank, and is furnished solely to provide limited introductory information regarding the Bank and does not purport to be comprehensive. Any financial information provided in this section is qualified in its entirety by the detailed information appearing in the Call Reports referenced above. The delivery hereof shall not create any implication that there has been no change in the affairs of the Bank since the date hereof.

Appendix A of the Reoffering Circular is hereby amended to read in its entirety as follows:

Appendix A

[DELETED AND REPLACED – SEE APPENDIX A TO SUPPLEMENT DATED MAY 2, 2011]

Supplement, dated October 29, 2010 to Reoffering Circular dated December 11, 2008, as supplemented as of December 16, 2008 (the "Reoffering Circular")

$54,000,000 **County of Carroll, Kentucky** **Environmental Facilities Revenue** **Refunding Bonds, 2006 Series B** **(Kentucky Utilities Company Project)**	**$77,947,405** **County of Carroll, Kentucky** **Environmental Facilities Revenue** **Bonds,** **2008 Series A** **(Kentucky Utilities Company Project)**

Effective as of October 29, 2010, each series of the above-referenced bonds (collectively, the "Bonds") will be further secured by the delivery to Deutsche Bank Trust Company Americas, as trustee for each series of Bonds (the "Trustee"), of a separate tranche of first mortgage bonds of Kentucky Utilities Company (the "Company"). The principal amount, maturity date and interest rate (or method of determining interest rates) of each such tranche of first mortgage bonds will be identical to the principal amount, maturity date and interest rate (or method of determining interest rates) of the applicable series of Bonds. The first mortgage bonds will only be payable, and interest thereon will only accrue, as described herein. See "Security," "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds" and "Summary of the First Mortgage Bonds" for more information regarding the first mortgage bonds. The first mortgage bonds will not provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase in accordance with the applicable Indenture (as hereinafter defined).

Please be advised that, as reflected in the Company's most recent financial statements that are filed on the Electronic Municipal Market Access (EMMA) system and are incorporated by reference herein, PPL Corporation has entered into an agreement with E.ON AG pursuant to which PPL Corporation would purchase all of the ownership interests of E.ON U.S. LLC, the Company's parent. Consummation of the transaction is subject to customary closing conditions, including receipt of all required regulatory approvals. Subject to receipt of such approvals, the transaction is expected to close by the end of 2010. If the transaction is completed, the Company will become an indirect wholly-owned subsidiary of PPL Corporation.

Except as otherwise specified herein, information in the Reoffering Circular referred to above has not been amended or modified and the information contained herein is qualified by reference to, and should be read in conjunction with, the Reoffering Circular, including information incorporated therein by reference. Terms not otherwise defined herein shall have the meanings ascribed to them in such Reoffering Circular.

The section of the Reoffering Circular captioned "Separate Series" is hereby amended to read in its entirety as follows:

Separate Series

The 2006 Series B Bonds and the 2008 Series A Bonds are separate series and optional or mandatory redemption of any series may be made in the manner described below without the redemption of the other series. Similarly, a default under one of the series of Bonds or one of the Loan Agreements will not necessarily constitute a default under the other series of Bonds or Loan Agreements. Each series of Bonds can bear interest at an Interest Rate Mode different from the Interest Rate Mode borne by the other series of Bonds. Unless specifically otherwise noted, any discussion herein and under the captions "Summary of the Bonds," "The Letter of Credit," "Security" "Summary of the Loan Agreement," "Summary of the First Mortgage Bonds," "Summary of the Indenture," "Enforceability of Remedies" and "Tax Treatment" applies equally, but separately, to the 2006 Series B Bonds and the 2008 Series A Bonds.

As used herein under such captions with respect to the 2006 Series B Bonds, the term "Project" shall mean the 2006 Series B Project, the term "Bonds" shall mean the 2006 Series B Bonds, the term "First Mortgage Bonds" shall mean the Carroll County Tranche 5 of the First Mortgage Bonds delivered to the 2006 Series B Trustee, the term "Loan Agreement" shall mean the 2006 Series B Loan Agreement pursuant to which the Issuer loaned the proceeds from the sale of the 2006 Series B Bonds to the Company, the term "Indenture" shall mean the 2006 Series B Indenture, the term "Remarketing Agent" shall mean Banc of America Securities LLC, the terms "Trustee" and "Tender Agent" shall mean the 2006 Series B Trustee and the term "Letter of Credit" shall mean the Letter of Credit delivered to the 2006 Series B Trustee.

As used herein under such captions with respect to the 2008 Series A Bonds, the term "Project" shall mean the 2008 Series A Project, the term "Bonds" shall mean the 2008 Series A Bonds, the term "First Mortgage Bonds" shall mean the Carroll County Tranche 7 of the First Mortgage Bonds delivered to the 2008 Series A Trustee the term "Loan Agreement" shall mean the 2008 Series A Loan Agreement pursuant to which the Issuer loaned the proceeds from the sale of the 2008 Series A Bonds to the Company, the term "Indenture" shall mean the 2008 Series A Indenture, the term "Remarketing Agent" shall mean Banc of America Securities LLC, the terms "Trustee" and "Tender Agent" shall mean the 2008 Series A Trustee and the term "Letter of Credit" shall mean the Letter of Credit delivered to the 2008 Series A Trustee.

The section of the Reoffering Circular captioned "Security; Limitation on Liens" is hereby amended to read in its entirety as follows:

Security

Payment of the principal of and interest and any premium on the Bonds will be secured by an assignment by the Issuer to the Trustee of the Issuer's interest in and to the Loan Agreement and all payments to be made pursuant thereto (other than certain indemnification and expense payments). Pursuant to the Loan Agreement, the Company will agree to pay, among other things, amounts sufficient to pay the aggregate principal amount of and premium, if any, on the Bonds, together with interest thereon as and when the same become due. The Company further will agree to make payments of the purchase price of the Bonds tendered for purchase to the extent that funds are not otherwise available therefor under the provisions of the Indenture.

The payment of the principal of and interest and any premium on the Bonds will be further secured by a separate tranche of the Company's First Mortgage Bonds, Collateral Series 2010 (the "First Mortgage Bonds") to be issued under an Indenture, dated as of October 1, 2010, as supplemented (the "First Mortgage Indenture"), between the Company and The Bank of New York Mellon, as trustee (the "First Mortgage Trustee"). The principal amount of the First Mortgage Bonds will equal the principal amount of the Bonds. If the Bonds become immediately due and payable as a result of a default in payment of the principal of, premium, if any, or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement and upon receipt by the First Mortgage Trustee of a written demand from the Trustee for redemption of the First Mortgage Bonds, or if all first mortgage bonds outstanding under the First Mortgage Indenture shall have been immediately due and payable, such First Mortgage Bonds will bear interest at the same interest rate or rates borne by the Bonds and the principal of such First Mortgage Bonds, together with interest accrued thereon from the last date or dates to which interest on the Bonds has been paid in full, will be payable in accordance with the Supplemental Indenture. See "Summary of the First Mortgage Bonds."

The First Mortgage Bonds are not intended to provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase in accordance with the Indenture. The First Mortgage Bonds are secured by a lien on certain property owned by the Company. In certain circumstances, the Company is permitted to reduce the aggregate principal amount of its First Mortgage Bonds held by the Trustee, but in no event to an amount lower than the aggregate outstanding principal amount of the Bonds.

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The section of the Reoffering Circular captioned "Summary of the Loan Agreement — Limitation on Liens" is hereby deleted. The sections of the Reoffering Circular captioned "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds"; " — Insurance"; " — Events of Default" and " — Remedies" are hereby added or amended, as applicable, to read in their entirety as follows:

Summary of the Loan Agreement

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Issuance and Delivery of First Mortgage Bonds

For the purpose of providing security for the Bonds, the Company will execute and deliver to the Trustee the First Mortgage Bonds. The principal amount of the First Mortgage Bonds executed and delivered to the Trustee will be equal to the aggregate principal amount of the Bonds. If the Bonds become immediately due and payable as a result of a default in payment of the principal of, premium, if any, or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement and upon receipt by the First Mortgage Trustee of a written demand from the Trustee for redemption of the First Mortgage Bonds, or if all first mortgage bonds outstanding under the First Mortgage Indenture shall have been immediately due and payable, such First Mortgage Bonds will bear interest at the same interest rate or rates borne by the Bonds and the principal of such First Mortgage Bonds, together with interest accrued thereon from the last date to which interest on the Bonds shall have been paid in full, will then be payable. See, however, "Summary of the Indenture — Waiver of Events of Default."

Upon payment of the principal of, premium, if any, and interest on any of the Bonds, and the surrender to and cancellation thereof by the Trustee, or upon provision for the payment thereof having been made in accordance with the Indenture, First Mortgage Bonds with corresponding principal amounts equal to the aggregate principal amount of the Bonds so surrendered and canceled or for the payment of which provision has been made, will be surrendered by the Trustee to the First Mortgage Trustee and will be canceled by the First Mortgage Trustee. The First Mortgage Bonds will be registered in the name of the Trustee and will be non transferable, except to effect transfers to any successor trustee under the Indenture.

Insurance

The Company has agreed to insure the Project in accordance with the provisions of the First Mortgage Indenture.

Events of Default

Each of the following events constitutes an "event of default" under the Loan Agreement:

(1) failure by the Company to pay the amounts required for payment of the principal of, including purchase price for tendered Bonds and redemption and acceleration prices, and interest accrued, on the Bonds, at the times specified therein taking into account any periods of grace provided in the Indenture and the Bonds for the

applicable payment of interest on the Bonds (see “Summary of the Indenture — Defaults and Remedies”);

(2) failure by the Company to observe and perform any covenant, condition or agreement, other than as referred to in paragraph (1) above, for a period of thirty days after written notice by the Issuer or Trustee, provided, however, that if such failure is capable of being corrected, but cannot be corrected in such 30-day period, it will not constitute an event of default under the Loan Agreement if corrective action with respect thereto is instituted within such period and is being diligently pursued;

(3) certain events of bankruptcy, dissolution, liquidation, reorganization or insolvency of the Company;

(4) the occurrence of an event of default under the Indenture; or

(5) all first mortgage bonds outstanding under the First Mortgage Indenture, if not already due, shall have become immediately due and payable, whether by declaration or otherwise, and such acceleration shall not have been rescinded or annulled by the First Mortgage Trustee.

Under the Loan Agreement, certain of the Company’s obligations (other than the Company’s obligations, among others, (i) not to permit any action which would result in interest paid on the Bonds being included in gross income for federal and Kentucky income taxes; (ii) to maintain its corporate existence and good standing, and to neither dispose of all or substantially all of its assets or consolidate with or merge into another corporation unless certain provisions of the Loan Agreement are satisfied; and (iii) to make loan payments and certain other payments under the provisions of the Loan Agreement) may be suspended if by reason of force majeure (as defined in the Loan Agreement) the Company is unable to carry out such obligations.

Remedies

Upon the happening of an event of default under the Loan Agreement, the Trustee, on behalf of the Issuer, may, among other things, take whatever action at law or in equity may appear necessary or desirable to collect the amounts then due and thereafter to become due, or to enforce performance and observance of any obligation, agreement or covenant of the Company, under the Loan Agreement, including any remedies available in respect of the First Mortgage Bonds.

In the event of a default in payment of the principal of, premium, if any, or interest on the Bonds and the acceleration of the maturity date of the Bonds (to the extent not already due and payable) as a consequence of such event of default, the Trustee may demand redemption of the First Mortgage Bonds. See "Summary of the First Mortgage Bonds" and "Summary of the Indenture — Defaults and Remedies." Any amounts collected upon the happening of any such event of default will be applied in accordance with the Indenture or, if the Bonds have been fully paid (or provision for payment thereof has been made in accordance with the Indenture) and all other liabilities of the Company accrued under the Indenture and the Loan Agreement have been paid or satisfied, made available to the Company.

* * * *

A new section is hereby added to the Reoffering Circular to read in its entirety as follows:

Summary of the First Mortgage Bonds

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the First Mortgage Bonds and the First Mortgage Indenture. This description is only a summary and does not purport to be complete and definitive. Reference is made to the First Mortgage Indenture and to the form of the First Mortgage Bonds for the detailed provisions thereof.

General

The First Mortgage Bonds, in a principal amount equal to the principal amount of the Bonds, were issued as a new tranche from a new series of first mortgage bonds under the First Mortgage Indenture (see "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds"). The statements herein made (being for the most part summaries of certain provisions of the First Mortgage Indenture) are subject to the detailed provisions of the First Mortgage Indenture, which is incorporated herein by this reference. Words or phrases italicized are defined in the First Mortgage Indenture.

The First Mortgage Bonds will mature on the same date and bear interest at the same rate or rates as the Bonds; however, the principal of and interest on the First Mortgage Bonds will not be payable other than upon the occurrence of an event of default under the Loan Agreement. If the Bonds become immediately due and payable as a result of a default in payment of the principal of, premium, if any, or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement, and if all first mortgage bonds outstanding under the First Mortgage Indenture shall not have become immediately due and payable following an event of default under the First Mortgage Indenture, the Company will be obligated to redeem the First Mortgage Bonds upon receipt by the First Mortgage Trustee of a Redemption Demand from the Trustee for redemption, at a redemption price equal to the principal amount thereof plus accrued interest at the rates borne by the Bonds from the last date to which interest on the Bonds has been paid.

The First Mortgage Bonds at all times will be in fully registered form registered in the name of the Trustee, will be non-negotiable, and will be non-transferable except to any successor trustee under the Indenture. Upon payment and cancellation of Bonds by the Trustee or the Paying Agent (other than any Bond or portion thereof that was canceled by the Trustee or the Paying Agent and for which one or more Bonds were delivered and authenticated pursuant to the Indenture), whether at maturity, by redemption or otherwise, or upon provision for the payment of the Bonds having been made in accordance with the Indenture, an equal principal amount of

First Mortgage Bonds will be deemed fully paid and the obligations of the Company thereunder will cease.

Security; Lien of the First Mortgage Indenture

General. Except as described below under this heading and under "— Issuance of Additional First Mortgage Bonds," and subject to the exceptions described under "— Satisfaction and Discharge," all first mortgage bonds issued under the First Mortgage Indenture, including the Bonds, will be secured, equally and ratably, by the lien of the First Mortgage Indenture, which constitutes, subject to permitted liens as described below, a first mortgage lien on substantially all of the Company's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity (other than property duly released from the lien of the First Mortgage Indenture in accordance with the provisions thereof and other than excepted property, as described below). Property that is subject to the lien of the First Mortgage Indenture is referred to herein as "Mortgaged Property."

The Company may obtain the release of property from the lien of the First Mortgage Indenture from time to time, upon the bases provided for such release in the First Mortgage Indenture. See "— Release of Property."

The Company may enter into supplemental indentures with the First Mortgage Trustee, without the consent of the holders of the first mortgage bonds, in order to subject additional property (including property that would otherwise be excepted from such lien) to the lien of the First Mortgage Indenture. This property would constitute *property additions* and would be available as a basis for the issuance of additional first mortgage bonds. See "— Issuance of Additional First Mortgage Bonds."

The First Mortgage Indenture provides that after-acquired property (other than *excepted property*) will be subject to the lien of the First Mortgage Indenture. However, in the case of consolidation or merger (whether or not the Company is the surviving company) or transfer of the Mortgaged Property as or substantially as an entirety, the First Mortgage Indenture will not be required to be a lien upon any of the properties either owned or subsequently acquired by the successor company except properties acquired from the Company in or as a result of such transfer, as well as improvements, extensions and additions (as defined in the First Mortgage Indenture) to such properties and renewals, replacements and substitutions of or for any part or parts thereof. See "— Consolidation, Merger and Conveyance of Assets as an Entirety."

Excepted Property. The lien of the First Mortgage Indenture does not cover, among other things, the following types of property: property located outside of Kentucky and not specifically subjected or required to be subjected to the lien of the First Mortgage Indenture; property not used by the Company in its electric generation, transmission and distribution business; cash and securities not paid, deposited or held under the First Mortgage Indenture; contracts, leases and other agreements of all kinds, contract rights, bills, notes and other instruments, revenues, accounts receivable, claims, demands and judgments; governmental and other licenses, permits, franchises, consents and allowances; intellectual property rights and other general intangibles; vehicles, movable equipment, aircraft and vessels; all goods, stock in trade, wares, merchandise and inventory held for the purpose of sale or lease in the ordinary course of business; materials, supplies, inventory and other personal property consumable in the operation of the Company's business; fuel; tools and equipment; furniture and furnishings; computers and data processing, telecommunications and other facilities used primarily for administrative or clerical purposes or otherwise not used in connection with the operation or maintenance of electric generation, transmission and distribution facilities; coal, ore, gas, oil and other minerals and timber rights; electric energy and capacity, gas, steam, water and other products generated, produced, manufactured, purchased or otherwise acquired; real property and facilities used primarily for the production or gathering of natural gas; property which has been released from the lien of the First Mortgage Indenture; and leasehold interests. Property of the Company not covered by the lien of the First Mortgage Indenture is referred to herein as excepted property. Properties held by any of the Company's subsidiaries, as well as properties leased from others, would not be subject to the lien of the First Mortgage Indenture.

Permitted Liens. The lien of the First Mortgage Indenture is subject to permitted liens described in the First Mortgage Indenture. Such *permitted liens* include liens existing at the execution date of the First Mortgage Indenture, purchase money liens and other liens placed or otherwise existing on property acquired by the Company after the execution date of the First Mortgage Indenture at the time the Company acquires it, tax liens and other governmental charges which are not delinquent or which are being contested in good faith, mechanics', construction and materialmen's liens, certain judgment liens, easements, reservations and rights of others (including governmental entities) in, and defects of title to, the Company's property, certain leases and leasehold interests, liens to secure public obligations, rights of others to take minerals, timber, electric energy or capacity, gas, water, steam or other products produced by the Company or by others on the Company's property, rights and interests of persons other than the Company arising out of agreements relating to the common ownership or joint use of property, and liens on the interests of such persons in such property and liens which have been bonded or for which other security arrangements have been made.

The First Mortgage Indenture also provides that the First Mortgage Trustee will have a lien, prior to the lien on behalf of the holders of the first mortgage bonds, including the First Mortgage Bonds, upon the Mortgaged Property as security for the Company's payment of its reasonable compensation and expenses and for indemnity against certain liabilities. Any such lien would be a *permitted lien* under the First Mortgage Indenture.

Issuance of Additional First Mortgage Bonds

The maximum principal amount of first mortgage bonds that may be authenticated and delivered under the First Mortgage Indenture is subject to the issuance restrictions described below; provided, however, that the maximum principal amount of first mortgage bonds outstanding at any one time shall not exceed One Quintillion Dollars ($1,000,000,000,000,000,000), which amount may be changed by supplemental indenture. First mortgage bonds of any series may be issued from time to time on the basis of, and in an aggregate principal amount not exceeding:

- 66 2/3% of the *cost* or *fair value* to the Company (whichever is less) of *property additions* (as described below) which do not constitute *funded property* (generally, *property additions* which have been made the basis of the authentication and delivery of first mortgage bonds, the release of Mortgaged Property or the withdrawal of cash, which have been substituted for retired *funded property* or which have been used for other specified purposes) after certain deductions and additions, primarily including adjustments to offset property retirements;

- the aggregate principal amount of *retired securities* (as described below); or

- an amount of cash deposited with the First Mortgage Trustee.

Property additions generally include any property which is owned by the Company and is subject to the lien of the First Mortgage Indenture except (with certain exceptions) goodwill, going concern value rights or intangible property, or any property the acquisition or construction of which is properly chargeable to one of the Company's operating expense accounts.

Retired securities means, generally, first mortgage bonds which are no longer outstanding under the First Mortgage Indenture, which have not been retired by the application of *funded cash* and which have not been used as the basis for the authentication and delivery of first mortgage bonds, the release of property or the withdrawal of cash.

The First Mortgage Bonds will be issued on the basis of *property additions*. At August 31, 2010, approximately $2.3 billion of *property additions* were available to be used as the basis for the authentication and delivery of first mortgage bonds.

Release of Property

Unless an *event of default* has occurred and is continuing, the Company may obtain the release from the lien of the First Mortgage Indenture of any Mortgaged Property, except for cash held by the First Mortgage Trustee, upon delivery to the First Mortgage Trustee of an amount in cash equal to the amount, if any, by which sixty-six and two-thirds percent (66-2/3%) of the cost of the property to be released (or, if less, the *fair value* to the Company of such property at the time it became *funded property*) exceeds the aggregate of:

- an amount equal to 66 2/3% of the aggregate principal amount of obligations secured by *purchase money liens* upon the property to be released and delivered to the First Mortgage Trustee;

- an amount equal to 66 2/3% of the *cost* or *fair value* to the Company (whichever is less) of certified *property additions* not constituting *funded property* after certain deductions and additions, primarily including adjustments to offset property retirements (except that such adjustments need not be made if such *property additions* were acquired or made within the 90-day period preceding the release);

- the aggregate principal amount of first mortgage bonds the Company would be entitled to issue on the basis of *retired securities* (with such entitlement being waived by operation of such release);

- the aggregate principal amount of first mortgage bonds delivered to the First Mortgage Trustee (with such first mortgage bonds to be canceled by the First Mortgage Trustee);

- any amount of cash and/or an amount equal to 66 2/3% of the aggregate principal amount of obligations secured by *purchase money liens* upon the property released delivered to the trustee or other holder of a lien prior to the lien of the First Mortgage Indenture, subject to certain limitations described in the First Mortgage Indenture; and

- any taxes and expenses incidental to any sale, exchange, dedication or other disposition of the property to be released.

As used in the First Mortgage Indenture, the term *purchase money* lien means, generally, a lien on the property being released which is retained by the transferor of such property or granted to one or more other persons in connection with the transfer or release thereof, or granted to or held by a trustee or agent for any such persons, and may include liens which cover property in addition to the property being released and/or which secure indebtedness in addition to indebtedness to the transferor of such property.

Unless an *event of default* has occurred and is continuing, property which is not *funded property* may generally be released from the lien of the First Mortgage Indenture without depositing any cash or property with the First Mortgage Trustee as long as (a) the aggregate amount of *cost* or *fair value* to the Company (whichever is less) of all *property additions* which do not constitute *funded property* (excluding the property to be released) after certain deductions and additions, primarily including adjustments to offset property retirements, is not less than zero or (b) the cost or *fair value* (whichever is less) of property to be released does not exceed the aggregate amount of the cost or fair value to the Company (whichever is less) of *property additions* acquired or made within the 90-day period preceding the release.

The First Mortgage Indenture provides simplified procedures for the release of minor properties and property taken by eminent domain, and provides for dispositions of certain obsolete property and grants or surrender of certain rights without any release or consent by the First Mortgage Trustee.

If the Company retains any interest in any property released from the lien of the First Mortgage Indenture, the First Mortgage Indenture will not become a lien on such property or such interest therein or any improvements, extensions or additions to such property or renewals, replacements or substitutions of or for such property or any part or parts thereof.

Withdrawal of Cash

Unless an *event of default* has occurred and is continuing, and subject to certain limitations, cash held by the First Mortgage Trustee may, generally, (1) be withdrawn by the Company (a) to the extent of sixty-six and two-thirds percent (66-2/3%) of the cost or *fair value* to the Company (whichever is less) of *property additions* not constituting *funded property*, after certain deductions and additions, primarily including adjustments to offset retirements (except that such adjustments need not be made if such *property additions* were acquired or made within the 90-day period preceding the withdrawal) or (b) in an amount equal to the aggregate principal amount of first mortgage bonds that the Company would be entitled to issue on the basis of *retired securities* (with the entitlement to such issuance being waived by operation of such withdrawal) or (c) in an amount equal to the aggregate principal amount of any outstanding first mortgage bonds delivered to the First Mortgage Trustee; or (2) upon the Company's request, be applied to (a) the purchase of first mortgage bonds in a manner and at a price approved by the Company or (b) the payment (or provision for payment) at stated maturity of any first mortgage bonds or the redemption (or provision for payment) of any first mortgage bonds which are redeemable; provided, however, that cash deposited with the First Mortgage Trustee as the basis for the authentication and delivery of first mortgage bonds may, in addition, be withdrawn in an amount not exceeding the aggregate principal amount of cash delivered to the First Mortgage Trustee for such purpose.

Events of Default

An "*event of default*" occurs under the First Mortgage Indenture if

- the Company does not pay any interest on any first mortgage bonds within 30 days of the due date;
- the Company does not pay principal or premium, if any, on any first mortgage bonds on the due date;
- the Company remains in breach of any other covenant (excluding covenants specifically dealt with elsewhere in this section) in respect of any first mortgage bonds for 90 days after the Company receives a written notice of default stating the Company is in breach and requiring remedy of the breach; the notice must be sent by either the First Mortgage Trustee or holders of 25% of the principal amount of outstanding first mortgage bonds; the First Mortgage Trustee or such holders can agree to extend the 90-day period and such an agreement to extend will be automatically deemed to occur if the Company initiates corrective action within such 90 day period and the Company is diligently pursuing such action to correct the default; or
- the Company files for bankruptcy or certain other events in bankruptcy, insolvency, receivership or reorganization occur.

Remedies

Acceleration of Maturity. If an event of default occurs and is continuing, then either the First Mortgage Trustee or the holders of not less than 25% in principal amount of the outstanding first mortgage bonds may declare the principal amount of all of the first mortgage bonds to be due and payable immediately.

Rescission of Acceleration. After the declaration of acceleration has been made and before the First Mortgage Trustee has obtained a judgment or decree for payment of the money due, such declaration and its consequences will be rescinded and annulled, if

- the Company pays or deposits with the First Mortgage Trustee a sum sufficient to pay:

    - all overdue interest;
    - the principal of and premium, if any, which have become due otherwise than by such declaration of acceleration and interest thereon;
    - interest on overdue interest to the extent lawful;
    - all amounts due to the First Mortgage Trustee under the First Mortgage Indenture; and
- all *events of default*, other than the nonpayment of the principal which has become due solely by such declaration of acceleration, have been cured or waived as provided in the First Mortgage Indenture.

For more information as to waiver of defaults, see "— Waiver of Default and of Compliance" below.

Appointment of Receiver and Other Remedies. Subject to the First Mortgage Indenture, under certain circumstances and to the extent permitted by law, if an *event of default* occurs and is continuing, the First Mortgage Trustee has the power to appoint a receiver of the Mortgaged Property, and is entitled to all other remedies available to mortgagees and secured parties under the Uniform Commercial Code or any other applicable law.

Control by Holders; Limitations. Subject to the First Mortgage Indenture, if an *event of default* occurs and is continuing, the holders of a majority in principal amount of the outstanding first mortgage bonds will have the right to

- direct the time, method and place of conducting any proceeding for any remedy available to the First Mortgage Trustee, or
- exercise any trust or power conferred on the First Mortgage Trustee.

The rights of holders to make direction are subject to the following limitations:

- the holders' directions may not conflict with any law or the First Mortgage Indenture; and
- the holders' directions may not involve the First Mortgage Trustee in personal liability where the First Mortgage Trustee believes indemnity is not adequate.

The First Mortgage Trustee may also take any other action it deems proper which is not inconsistent with the holders' direction.

In addition, the First Mortgage Indenture provides that no holder of any first mortgage bond will have any right to institute any proceeding, judicial or otherwise, with respect to the First Mortgage Indenture for the appointment of a receiver or for any other remedy thereunder unless

- that holder has previously given the First Mortgage Trustee written notice of a continuing *event of default*;

- the holders of 25% in aggregate principal amount of the outstanding first mortgage bonds have made written request to the First Mortgage Trustee to institute proceedings in respect of that *event of default* and have offered the First Mortgage Trustee reasonable indemnity against costs, expenses and liabilities incurred in complying with such request; and

- for 60 days after receipt of such notice, request and offer of indemnity, the First Mortgage Trustee has failed to institute any such proceeding and no direction inconsistent with such request has been given to the First Mortgage Trustee during such 60-day period by the holders of a majority in aggregate principal amount of outstanding first mortgage bonds.

Furthermore, no holder of any first mortgage bonds will be entitled to institute any such action if and to the extent that such action would disturb or prejudice the rights of other holders of first mortgage bonds.

However, each holder of any first mortgage bonds has an absolute and unconditional right to receive payment when due and to bring a suit to enforce that right.

Notice of Default. The First Mortgage Trustee is required to give the holders of the first mortgage bonds notice of any default under the First Mortgage Indenture to the extent required by the Trust Indenture Act, unless such default has been cured or waived; except that in the case of an *event of default* of the character specified in the third bullet point under "— Events of Default" (regarding a breach of certain covenants continuing for 90 days after the receipt of a written notice of default), no such notice shall be given to such holders until at least 60 days after the occurrence thereof. The Trust Indenture Act currently permits the First Mortgage Trustee to withhold notices of default (except for certain payment defaults) if the First Mortgage Trustee in good faith determines the withholding of such notice to be in the interests of the holders of the first mortgage bonds.

The Company will furnish the First Mortgage Trustee with an annual statement as to its compliance with the conditions and covenants in the First Mortgage Indenture.

Waiver of Default and of Compliance. The holders of a majority in aggregate principal amount of the outstanding first mortgage bonds may waive, on behalf of the holders of all outstanding first mortgage bonds, any past default under the First Mortgage Indenture, except a default in the payment of principal, premium or interest, or with respect to compliance with certain provisions of the First Mortgage Indenture that cannot be amended without the consent of the holder of each outstanding first mortgage bond affected.

Compliance with certain covenants in the First Mortgage Indenture or otherwise provided with respect to first mortgage bonds may be waived by the holders of a majority in aggregate principal amount of the affected first mortgage bonds, considered as one class.

Consolidation, Merger and Conveyance of Assets as an Entirety

Subject to the provisions described below, the Company has agreed to preserve its corporate existence.

The Company has agreed not to consolidate with or merge with or into any other entity or convey, transfer or lease the Mortgaged Property as or substantially as an entirety to any entity unless

- the entity formed by such consolidation or into which the Company merges, or the entity which acquires or which leases the Mortgaged Property substantially as an entirety, is an entity organized and existing under the laws of the United States of America or any State or Territory thereof or the District of Columbia, and

  - expressly assumes, by supplemental indenture, the due and punctual payment of the principal of, and premium and interest on, all the outstanding first mortgage bonds and the performance of all of the Company's covenants under the First Mortgage Indenture, and

  - such entity confirms the lien of the First Mortgage Indenture on the Mortgaged Property, including property thereafter acquired by such entity which constitutes an improvement, extension or addition to the Mortgaged Property or a renewal, replacement or substitution thereof;

- in the case of a lease, such lease is made expressly subject to termination by (i) the Company or by the First Mortgage Trustee and (ii) the purchaser of the property so leased at any sale thereof, at any time during the continuance of an *event of default*; and

- immediately after giving effect to such transaction, no *event of default,* and no event which after notice or lapse of time or both would become an *event of default,* will have occurred and be continuing.

In the case of the conveyance or other transfer of the Mortgaged Property as or substantially as an entirety to any other person, upon the satisfaction of all the conditions described above the Company would be released and discharged from all obligations under the First Mortgage Indenture and on the first mortgage bonds then outstanding unless the Company elects to waive such release and discharge.

The First Mortgage Indenture does not prevent or restrict:

- any consolidation or merger after the consummation of which the Company would be the surviving or resulting entity; or

- any conveyance or other transfer, or lease, of any part of the Mortgaged Property which does not constitute the entirety or substantially the entirety thereof.

If following a conveyance or other transfer, or lease, of any part of the Mortgaged Property, the fair value of the Mortgaged Property retained by the Company exceeds an amount equal to three-halves (3/2) of the aggregate principal amount of all outstanding first mortgage bonds, then the part of the Mortgaged Property so conveyed, transferred or leased shall be deemed not to constitute the entirety or substantially the entirety of the Mortgaged Property. This fair value will be determined within 90 days of the conveyance or transfer by an independent expert that the Company selects and that is approved by the First Mortgage Trustee.

Modification of First Mortgage Indenture

Without Holder Consent. Without the consent of any holders of first mortgage bonds, the Company and the First Mortgage Trustee may enter into one or more supplemental indentures for any of the following purposes:

- to evidence the succession of another entity to the Company;

- to add one or more covenants or other provisions for the benefit of the holders of all or any series or tranche of first mortgage bonds, or to surrender any right or power conferred upon the Company;

- to correct or amplify the description of any property at any time subject to the lien of the First Mortgage Indenture; or to better assure, convey and confirm unto the First Mortgage Trustee any property subject or required to be subjected to the lien of the First Mortgage Indenture; or to subject to the lien of the First Mortgage Indenture additional property (including property of others), to specify any additional Permitted Liens with respect to such additional property and to modify the provisions in the First Mortgage Indenture for dispositions of certain types of property without release in order to specify any additional items with respect to such additional property;

- to add any additional e*vents of default*, which may be stated to remain in effect only so long as the first mortgage bonds of any one more particular series remains outstanding;

- to change or eliminate any provision of the First Mortgage Indenture or to add any new provision to the First Mortgage Indenture that does not adversely affect the interests of the holders in any material respect;

- to establish the form or terms of any series or tranche of first mortgage bonds;

- to provide for the issuance of bearer securities;

- to evidence and provide for the acceptance of appointment of a successor First Mortgage Trustee or by a co-trustee or separate trustee;

- to provide for the procedures required to permit the utilization of a noncertificated system of registration for any series or tranche of first mortgage bonds;

- to change any place or places where

- the Company may pay principal, premium and interest,
- first mortgage bonds may be surrendered for transfer or exchange, and
- notices and demands to or upon the Company may be served;

- to amend and restate the First Mortgage Indenture as originally executed, and as amended from time to time, with such additions, deletions and other changes that do not adversely affect the interest of the holders in any material respect;
- to cure any ambiguity, defect or inconsistency or to make any other changes that do not adversely affect the interests of the holders in any material respect; or
- to increase or decrease the maximum principal amount of first mortgage bonds that may be outstanding at any time.

In addition, if the Trust Indenture Act is amended after the date of the First Mortgage Indenture so as to require changes to the First Mortgage Indenture or so as to permit changes to, or the elimination of, provisions which, at the date of the First Mortgage Indenture or at any time thereafter, were required by the Trust Indenture Act to be contained in the First Mortgage Indenture, the First Mortgage Indenture will be deemed to have been amended so as to conform to such amendment or to effect such changes or elimination, and the Company and the First Mortgage Trustee may, without the consent of any holders, enter into one or more supplemental indentures to effect or evidence such amendment.

With Holder Consent. Except as provided above, the consent of the holders of at least a majority in aggregate principal amount of the first mortgage bonds of all outstanding series, considered as one class, is generally required for the purpose of adding to, or changing or eliminating any of the provisions of, the First Mortgage Indenture pursuant to a supplemental indenture. However, if less than all of the series of outstanding first mortgage bonds are directly affected by a proposed supplemental indenture, then such proposal only requires the consent of the holders of a majority in aggregate principal amount of the outstanding first mortgage bonds of all directly affected series, considered as one class. Moreover, if the first mortgage bonds of any series have been issued in more than one tranche and if the proposed supplemental indenture directly affects the rights of the holders of first mortgage bonds of one or more, but less than all, of such tranches, then such proposal only requires the consent of the holders of a majority in aggregate principal amount of the outstanding first mortgage bonds of all directly affected tranches, considered as one class.

However, no amendment or modification may, without the consent of the holder of each outstanding first mortgage bond directly affected thereby,

- change the stated maturity of the principal or interest on any first mortgage bond (other than pursuant to the terms thereof), or reduce the principal amount, interest or premium payable (or method of calculating such rates)or change the currency in which any first mortgage bond is payable, or impair the right to bring suit to enforce any payment;

- create any lien (not otherwise permitted by the First Mortgage Indenture) ranking prior to the lien of the First Mortgage Indenture with respect to all or substantially all of the Mortgaged Property, or terminate the lien of the First Mortgage Indenture on all or substantially all of the Mortgaged Property (other than in accordance with the terms of the First Mortgage Indenture), or deprive any holder of the benefits of the security of the lien of the First Mortgage Indenture;

- reduce the percentages of holders whose consent is required for any supplemental indenture or waiver of compliance with any provision of the First Mortgage Indenture or of any default thereunder and its consequences, or reduce the requirements for quorum and voting under the First Mortgage Indenture; or

- modify certain of the provisions of the First Mortgage Indenture relating to supplemental indentures, waivers of certain covenants and waivers of past defaults with respect to first mortgage bonds.

A supplemental indenture which changes, modifies or eliminates any provision of the First Mortgage Indenture expressly included solely for the benefit of holders of first mortgage bonds of one or more particular series or tranches will be deemed not to affect the rights under the First Mortgage Indenture of the holders of first mortgage bonds of any other series or tranche.

Satisfaction and Discharge

Any first mortgage bonds or any portion thereof will be deemed to have been paid and no longer outstanding for purposes of the First Mortgage Indenture and, at the Company's election, the Company's entire indebtedness with respect to those securities will be satisfied and discharged, if there shall have been irrevocably deposited with the First Mortgage Trustee or any Paying Agent (other than the Company), in trust:

- money sufficient, or

- in the case of a deposit made prior to the maturity of such first mortgage bonds, non-redeemable *eligible obligations* (as defined in the First Mortgage Indenture) sufficient, or

- a combination of the items listed in the preceding two bullet points, which in total are sufficient,

to pay when due the principal of, and any premium, and interest due and to become due on such first mortgage bonds or portions of such first mortgage bonds on and prior to their maturity.

The Company's right to cause its entire indebtedness in respect of the first mortgage bonds of any series to be deemed to be satisfied and discharged as described above will be subject to the satisfaction of any conditions specified in the instrument creating such series.

The First Mortgage Indenture will be deemed satisfied and discharged when no first mortgage bonds remain outstanding and when the Company has paid all other sums payable by it under the First Mortgage Indenture.

All moneys the Company pays to the First Mortgage Trustee or any Paying Agent on First Mortgage Bonds that remain unclaimed at the end of two years after payments have become due may be paid to or upon the Company's order. Thereafter, the holder of such First Mortgage Bond may look only to the Company for payment.

Duties of the First Mortgage Trustee; Resignation and Removal of the First Mortgage Trustee; Deemed Resignation

The First Mortgage Trustee will have, and will be subject to, all the duties and responsibilities specified with respect to an indenture trustee under the Trust Indenture Act. Subject to these provisions, the First Mortgage Trustee will be under no obligation to exercise any of the powers vested in it by the First Mortgage Indenture at the request of any holder of first mortgage bonds, unless offered reasonable indemnity by such holder against the costs, expenses and liabilities which might be incurred thereby. The First Mortgage Trustee will not be required to expend or risk its own funds or otherwise incur financial liability in the performance of its duties if the First Mortgage Trustee reasonably believes that repayment or adequate indemnity is not reasonably assured to it.

The First Mortgage Trustee may resign at any time by giving written notice to the Company.

The First Mortgage Trustee may also be removed by act of the holders of a majority in principal amount of the then outstanding first mortgage bonds of any series.

No resignation or removal of the First Mortgage Trustee and no appointment of a successor trustee will become effective until the acceptance of appointment by a successor trustee in accordance with the requirements of the First Mortgage Indenture.

Under certain circumstances, the Company may appoint a successor trustee and if the successor accepts, the First Mortgage Trustee will be deemed to have resigned.

Evidence to be Furnished to the First Mortgage Trustee

Compliance with First Mortgage Indenture provisions is evidenced by written statements of the Company's officers or persons selected or paid by the Company. In certain cases, opinions of counsel and certifications of an engineer, accountant, appraiser or other expert (who in some cases must be independent) must be furnished. In addition, the First Mortgage Indenture requires the Company to give to the First Mortgage Trustee, not less than annually, a brief statement as to the Company's compliance with the conditions and covenants under the First Mortgage Indenture.

Miscellaneous Provisions

The First Mortgage Indenture provides that certain first mortgage bonds, including those for which payment or redemption money has been deposited or set aside in trust as described under "— Satisfaction and Discharge" above, will not be deemed to be "outstanding" in determining whether the holders of the requisite principal amount of the outstanding first mortgage bonds have given or taken any demand, direction, consent or other action under the First Mortgage Indenture as of any date, or are present at a meeting of holders for quorum purposes.

The Company will be entitled to set any day as a record date for the purpose of determining the holders of outstanding first mortgage bonds of any series entitled to give or take any demand, direction, consent or other action under the First Mortgage Indenture, in the manner and subject to the limitations provided in the First Mortgage Indenture. In certain circumstances, the First Mortgage Trustee also will be entitled to set a record date for action by holders. If such a record date is set for any action to be taken by holders of particular first mortgage bonds, such action may be taken only by persons who are holders of such first mortgage bonds on the record date.

Governing Law

The First Mortgage Indenture and the first mortgage bonds provide that they are to be governed by and construed in accordance with the laws of the State of New York except where the Trust Indenture Act is applicable or where otherwise required by law. The effectiveness of the lien of the First Mortgage Indenture, and the perfection and priority thereof, will be governed by Kentucky law.

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The sections of the Reoffering Circular captioned "Summary of the Indenture — Surrender of First Mortgage Bonds"; "— Defaults and Remedies"; "— Waiver of Events of Default"; and "— Voting of First Mortgage Bonds Held by Trustee" are hereby added or amended, as applicable, to read in their entirety as follows:

Summary of the Indenture

*   *   *   *

Surrender of First Mortgage Bonds

Upon payment of any principal of, premium, if any, and interest on any of the Bonds which reduces the principal amount of Bonds outstanding, or upon provision for the payment thereof having been made in accordance with the Indenture, First Mortgage Bonds in a principal amount equal to the principal amount of the Bonds so paid, or for the payment of which such provision has been made, shall be surrendered by the Trustee to the First Mortgage Trustee. The First Mortgage Bonds so surrendered shall be deemed fully paid and the obligations of the Company thereunder terminated.

Defaults and Remedies

Each of the following events constitutes an "Event of Default" under the Indenture:

(1) Failure to make payment of any installment of interest on any Bond, (a) if such Bond bears interest at other than the Long Term Rate, within a period of one Business Day from the due date and (b) if such Bond bears interest at the Long Term Rate, within a period of five Business Days from the date due;

(2) Failure to make punctual payment of the principal of, or premium, if any, on any Bond on the due date, whether at the stated maturity thereof, or upon proceedings for redemption, or upon the maturity thereof by declaration or if payment of the purchase price of any Bond required to be purchased pursuant to the Indenture is not made when such payment has become due and payable;

(3) Failure of the Issuer to perform or observe any other of the covenants, agreements or conditions in the Indenture or in the Bonds which failure continues for a period of 30 days after written notice by the Trustee, provided, however, that if such failure is capable of being cured, but cannot be cured in such 30-day period, it will not constitute an event of default under the Indenture if corrective action in respect of such failure is instituted within such 30-day period and is being diligently pursued;

(4) The occurrence of an "event of default" under the Loan Agreement (see "Summary of the Loan Agreement — Events of Default");

(5) Written notice from the Credit Facility Issuer to the Trustee of an event of default under the Reimbursement Agreement, by reason of which the Trustee has been directed to accelerate the Bonds;

(6) If a Credit Facility is then held by the Trustee, on or before the close of business on the tenth calendar day following the honoring of a drawing under such Credit Facility to pay interest on the bonds on an Interest Payment Date, written notice from the Credit Facility Issuer to the Trustee that the interest component of the Credit Facility will not be reinstated; or

(7) All first mortgage bonds outstanding under the First Mortgage Indenture, if not already due, shall have become due and payable, whether by declaration or otherwise, and such acceleration shall not have been rescinded by the First Mortgage Trustee.

Upon the occurrence of an Event of Default under clauses (1), (2), (5), (6) or (7) above, the Trustee must: (i) enforce each and every right granted to the Trustee as a holder of the First Mortgage Bonds (see "Summary of the First Mortgage Bonds"), (ii) declare the principal of all Bonds and interest accrued thereon to be immediately due and payable, (iii) declare all payments under the Loan Agreement to be immediately due and payable and enforce each and every other right granted to the Issuer under the Loan Agreement for the benefit of the Bondholders and (iv) if a Credit Facility securing the Bonds is in effect, make an immediate drawing under the Credit Facility in accordance with its terms and deposit the proceeds of such drawing in the Bond Fund pending application to the payment of principal of the Bonds, subject to the provisions of the Indenture reserving to the Credit Facility Issuer the right to direct default proceedings and providing for termination of default proceedings upon certain occurrences.

Interest on the Bonds will cease to accrue on the date of issuance of the declaration of acceleration of payment of principal and interest on the Bonds.

In exercising such rights, the Trustee shall take any action that, in the judgment of the Trustee, would best serve the interests of the registered owners. Upon the occurrence of an Event of Default under the Indenture, the Trustee may also proceed to pursue any available remedy by suit at law or in equity to enforce the payment of the principal of, premium, if any, and interest on the Bonds then outstanding.

If an Event of Default under the Indenture shall occur and be continuing and the maturity date of the Bonds has been accelerated (to the extent the Bonds are not already due and payable) as a consequence of such event of default, the Trustee may, and upon the written request of the registered owners holding not less than 25% in principal amount of all Bonds then outstanding and upon receipt of indemnity satisfactory to it shall, exercise such rights as it shall possess under the First Mortgage Indenture as a holder of the First Mortgage Bonds and shall also issue a Redemption Demand for such First Mortgage Bonds to the First Mortgage Trustee.

If the Trustee recovers any moneys following an Event of Default, unless the principal of the Bonds shall have been declared due and payable, all such moneys shall be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and the payment of any sums due and payable to the

United States pursuant to Section 148(f) of the Code, (ii) to the payment of all interest then due on the Bonds and (iii) to the payment of unpaid principal and premium, if any, of the Bonds. If the principal of the Bonds has become due or has been accelerated, such moneys shall be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and (ii) to the payment of principal of and interest then due and unpaid on the Bonds. In each case, however, Trustee and Paying Agent fees or costs will not be payable from moneys derived from Credit Facility drawings, any remarketing proceeds or moneys constituting certain Available Moneys under the Indenture.

No Bondholder may institute any suit or proceeding in equity or at law for the enforcement of the Indenture unless an Event of Default has occurred of which the Trustee has been notified or is deemed to have notice, and registered owners holding not less than 25% in aggregate principal amount of Bonds then outstanding shall have made written request to the Trustee to proceed to exercise the powers granted under the Indenture or to institute such action in their own name and the Trustee shall fail or refuse to exercise its powers within a reasonable time after receipt of indemnity satisfactory to it.

Any judgment against the Issuer pursuant to the exercise of rights under the Indenture shall be enforceable only against specific assigned payments, funds and accounts under the Indenture in the hands of the Trustee. No deficiency judgment shall be authorized against the general credit of the Issuer.

No default under paragraph (3) above shall constitute an Event of Default until actual notice is given to the Issuer and the Company by the Trustee or to the Issuer, the Company and the Trustee by the registered owners holding not less than 25% in aggregate principal amount of all Bonds outstanding and the Issuer and the Company shall have had thirty days after such notice to correct the default and failed to do so. If the default is such that it cannot be corrected within the applicable period but is capable of being cured, it will not constitute an Event of Default if corrective action is instituted by the Issuer or the Company within the applicable period and diligently pursued until the default is corrected.

Notwithstanding the foregoing, in addition to the rights of the Trustee and the Bondholders to direct proceedings as described above, if a Credit Facility is in effect, for so long as such Credit Facility is outstanding and the Credit Facility Issuer is not in default in its duties under the Indenture or the Credit Facility, the Credit Facility Issuer will have the absolute right to direct all proceedings on behalf of the Bondholders of the Bonds. Additionally, if the Event of Default which has occurred is an Event of Default under paragraphs (5) or (6) above, the Credit Facility Issuer, if any, will have no right to direct the Trustee or the Bondholders with respect to any matters, including remedies, and the holders of a majority in aggregate principal amount of the Bonds then outstanding, will have the right, at any time, by an instrument or instruments in writing executed and delivered to the Trustee, to direct the time, method and place of conducting all proceedings to be taken in connection with the enforcement of the terms and conditions of the Indenture, or for the appointment of a receiver or any other proceedings hereunder; provided, that such direction shall not be otherwise than in accordance with the provisions of law and of the Indenture.

If an Event of Default has occurred under the Indenture due to failure by the Credit Facility Issuer, if any, to honor a properly presented and conforming drawing by the Trustee under the Credit Facility then in effect in accordance with the terms thereof, all obligations of the Trustee to the Credit Facility Issuer and all rights of such Credit Facility Issuer under the Indenture will be suspended until the earlier of the cure of such failure or all of the Bonds have been paid in full.

Waiver of Events of Default

Except as provided below, the Trustee may in its discretion waive any Event of Default under the Indenture and shall do so upon the written request of the registered owners holding a majority in principal amount of all Bonds then outstanding. If, after the principal of all Bonds then outstanding shall have been declared to be due and payable as a result of a default under the Indenture and prior to any judgment or decree for the appointment of a receiver or for the payment of the moneys due shall have been entered, (i) the Company has caused to be deposited with the Trustee a sum sufficient to pay all matured installments of interest upon all Bonds and the principal of and premium, if any, on any and all Bonds which shall have become due otherwise than by reason of such declaration and the expenses of the Trustee in connection with such default (with interest thereon as provided in the Indenture) and (ii) all Events of Default under the Indenture (other than nonpayment of the principal of Bonds due by said declaration) shall have been remedied, then such Event of Default shall be deemed waived and such declaration and its consequences rescinded and annulled by the Trustee. Such waiver, rescission and annulment shall be binding upon all Bondholders. No such waiver, rescission and annulment shall extend to or affect any subsequent Event of Default or impair any right or remedy consequent thereon.

Upon any waiver or rescission as described above or any discontinuance or abandonment of proceedings under the Indenture, the Trustee shall immediately rescind in writing any Redemption Demand of First Mortgage Bonds previously given to the First Mortgage Trustee. The rescission under the First Mortgage Indenture of a declaration that all first mortgage bonds outstanding under the First Mortgage Indenture are immediately due and payable shall also constitute a waiver of an Event of Default described in paragraph (6) under the subcaption "—Defaults and Remedies" above and a waiver and rescission of its consequences, provided that no such waiver or rescission shall extend to or affect any subsequent or other default or impair any right consequent thereon.

The Trustee may not waive any default under clauses (5) or (6) above unless the Trustee has received in writing from the Credit Facility Issuer a written notice of full reinstatement of the full amount of the Credit Facility and a written rescission of the notice of the Event of Default.

Notwithstanding the foregoing, nothing in the Indenture shall affect the right of a registered owner to enforce the payment of principal of, premium, if any, and interest on the Bonds after the maturity thereof.

Voting of First Mortgage Bonds Held by Trustee

The Trustee, as holder of the First Mortgage Bonds, shall attend any meeting of holders of first mortgage bonds outstanding under the First Mortgage Indenture as to which it receives due notice. The Trustee shall vote the First Mortgage Bonds held by it, or shall consent with respect thereto, proportionally in the way in which the Trustee reasonably believes will be the vote or consent of all other holders of first mortgage bonds outstanding under the First Mortgage Indenture then eligible to vote or consent.

Notwithstanding the foregoing, the Trustee may not vote the First Mortgage Bonds in favor of, or give consent to, any action which, in the Trustee's opinion, would materially adversely affect the First Mortgage Bonds in a manner not generally shared by all other series of first mortgage bonds, except upon notification by the Trustee to the registered owners of all Bonds then outstanding of such proposal and consent thereto of the registered owners of at least 66 2/3% in aggregate principal amount of all Bonds then outstanding.

NOT A NEW ISSUE **BOOK-ENTRY ONLY**

On February 23, 2007 and October 17, 2008, the dates on which the Bonds were originally issued, Bond Counsel delivered its opinions that stated that, subject to the conditions and exceptions set forth under the caption "Tax Treatment," under then current law, interest on each series of Bonds would be excludable from the gross income of the recipients thereof for federal income tax purposes, except that no opinion was expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" or a "related person" of the related Project as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on each series of Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. Such interest may be subject to certain federal income taxes imposed on certain corporations, including imposition of the branch profits tax on a portion of such interest. Bond Counsel was further of the opinion that interest on each series of Bonds would be excludable from the gross income of the recipients thereof for Kentucky income tax purposes and that, under then current law, the principal of each series of Bonds would be exempt from ad valorem taxes in Kentucky. Such opinions have not been updated as of the date hereof and no continuing tax exemption opinions are expressed by Bond Counsel. However, in connection with the conversion of the interest rate mode on each series of Bonds to the Weekly Rate, as described in this Reoffering Circular, Bond Counsel will deliver its opinions to the effect that the conversion of the interest rate on each series of Bonds and the delivery of a letter of credit (a) is authorized or permitted by the Act and the related Indenture and (b) will not adversely affect the validity of the Bonds or any exclusion of the interest thereon from the gross income of the owners of the Bonds for federal income tax purposes. See "Tax Treatment" in this Reoffering Circular.

$54,000,000
County of Carroll, Kentucky
Environmental Facilities Revenue Refunding Bonds, 2006 Series B
(Kentucky Utilities Company Project)
Due: October 1, 2034

$77,947,405
County of Carroll, Kentucky
Environmental Facilities Revenue Bonds 2008 Series A
(Kentucky Utilities Company Project)
Due: February 1, 2032

Conversion Date: December 19, 2008

The Bonds of each series (individually, the "2006 Series B Bonds" and the "2008 Series A Bonds" and, collectively, the "Bonds") are special and limited obligations of the County of Carroll, Kentucky (the "Issuer"), payable by the Issuer solely from and secured by payments to be received by the Issuer pursuant to separate Loan Agreements with

Kentucky Utilities Company

(the "Company"), except as payable from proceeds of such Bonds or investment earnings thereon. The Bonds do not constitute general obligations of the Issuer or a charge against the general credit or taxing powers thereof or of the Commonwealth of Kentucky or any other political subdivision of Kentucky. The Bonds will not be entitled to the benefits of any financial guaranty insurance policies.

The 2006 Series B Bonds were originally issued on February 23, 2007 and the 2008 Series A Bonds were originally issued on October 17, 2008, each as a separate series. The 2006 Series B Bonds currently bear interest at a Dutch Auction Rate, and the 2008 Series A Bonds currently bear interest at a Flexible Rate. Pursuant to the Indentures under which the Bonds were issued, the Company has elected to convert the interest rate mode on each of the 2006 Series B Bonds and the 2008 Series A Bonds to a Weekly Rate, effective as of December 19, 2008 (the "Conversion Date"). The Bonds are subject to mandatory purchase on the Conversion Date and are being reoffered hereby. Banc of America Securities LLC will serve as the Remarketing Agent for the Bonds.

From and after the Conversion Date through December 18, 2009 (the Letter of Credit (as defined below) expiration date, subject to extension or earlier termination), payment of the principal of and interest on the Bonds when due will be paid with funds drawn under an irrevocable transferable direct pay letter of credit (the "Letter of Credit") issued by

COMMERZBANK AG, NEW YORK BRANCH

The Letter of Credit will permit the Trustee to draw with respect to the Bonds up to an amount sufficient to pay (i) the principal thereof (or that portion of the purchase price corresponding to principal) plus (ii) interest thereon (or that portion of the purchase price corresponding to interest) at an assumed rate of 15% per annum for at least 45 days.

From the Conversion Date, each series of Bonds will bear interest at a Weekly Rate, determined by the Remarketing Agent in accordance with the applicable Indenture, payable on the first Business Day of each calendar month, commencing on January 2, 2009. The interest rate period, interest rate and Interest Rate Mode for each series of Bonds will be subject to change under certain conditions, as described in this Reoffering Circular. The Bonds of each series are subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption following a determination of taxability prior to maturity, as described in this Reoffering Circular. The Bonds of each series are subject to mandatory purchase on any date on which the Bonds are converted to a different Interest Rate Mode and upon the expiration of the Letter of Credit or any Alternate Credit Facility.

The Bonds of each series are separate series, and the sale and delivery of one series is not dependent on the sale and delivery of any other series.

The Bonds are registered in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company ("DTC"), New York, New York. DTC will act as securities depository. Except as described herein, purchases of beneficial ownership interests in the Bonds will be made in book-entry-only form in denominations of $100,000 and multiples thereof; provided that one 2008 Series A Bond may be in the denomination of, or include an additional, $47,405. Purchasers will not receive certificates representing their beneficial interests in the Bonds. See the information contained under the caption "Summary of the Bonds—Book-Entry-Only System" below. The principal of, premium, if any, and interest on the Bonds will be paid by Deutsche Bank Trust Company Americas, as Trustee, to Cede & Co., as long as Cede & Co. is the registered owner of the Bonds. Disbursement of such payments to the DTC Participants is the responsibility of DTC, and disbursement of such payments to the purchasers of beneficial ownership interests is the responsibility of DTC's Direct and Indirect Participants, as described below.

PRICE: 100%

The Bonds are reoffered subject to prior sale, withdrawal or modification of the offer without notice (provided, however, that any such notice of withdrawal must be given on the Business Day prior to the Conversion Date) and to the approval of legality by Stoll Keenon Ogden PLLC, Louisville, Kentucky, as Bond Counsel and upon satisfaction of certain conditions. Certain legal matters will be passed upon for the Company by its counsel, Jones Day, Chicago, Illinois, and John R. McCall, Esq., Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer of the Company, for the Issuer by its County Attorney, and for the Remarketing Agent by its counsel, Winston & Strawn LLP, Chicago, Illinois. It is expected that the Bonds will be available for redelivery to DTC in New York, New York on or about December 19, 2008.

Banc of America Securities LLC

Dated: December 11, 2008

No dealer, broker, salesman or other person has been authorized by the Issuer, the Company or the Remarketing Agent to give any information or to make any representation with respect to the Bonds, other than those contained in this Reoffering Circular, and, if given or made, such other information or representation must not be relied upon as having been authorized by any of the foregoing. The Remarketing Agent has provided the following sentence for inclusion in this Reoffering Circular. The Remarketing Agent has reviewed the information in this Reoffering Circular in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Remarketing Agent does not guarantee the accuracy or completeness of such information. The information and expressions of opinion herein are subject to change without notice and neither the delivery of this Reoffering Circular nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the parties referred to above since the date hereof. The information set forth herein with respect to the Issuer has been obtained from the Issuer, and all other information has been obtained from the Company and from other sources that are believed to be reliable, but it is not guaranteed as to accuracy or completeness by, and is not to be construed as a representation by, the Remarketing Agent.

In connection with the reoffering of the Bonds, the Remarketing Agent may over-allot or effect transactions which stabilize or maintain the market prices of the Bonds at levels above those that might otherwise prevail in the open market. Such stabilizing, if commenced, may be discontinued at any time.

IN MAKING AN INVESTMENT DECISION, INVESTORS MUST RELY ON THEIR OWN EXAMINATION OF THE TERMS OF THE REOFFERING, INCLUDING THE MERITS AND RISKS INVOLVED. THESE SECURITIES HAVE NOT BEEN RECOMMENDED BY ANY FEDERAL OR STATE SECURITIES COMMISSION OR REGULATORY AUTHORITY. FURTHERMORE, THE FOREGOING AUTHORITIES HAVE NOT CONFIRMED THE ACCURACY OR DETERMINED THE ADEQUACY OF THIS DOCUMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

Table of Contents

$54,000,000 **County of Carroll, Kentucky** **Environmental Facilities Revenue Refunding Bonds, 2006 Series B** **(Kentucky Utilities Company Project)** **Due: October 1, 2034**	**$77,947,405** **County of Carroll, Kentucky** **Environmental Facilities Revenue Bonds 2008 Series A** **(Kentucky Utilities Company Project)** **Due: February 1, 2032**

Introductory Statement

This Reoffering Circular, including the cover page and appendices, is provided to furnish information in connection with the reoffering by the County of Carroll, Kentucky (the "Issuer") of its (i) Environmental Facilities Revenue Refunding Bonds, 2006 Series B (Kentucky Utilities Company Project, in the aggregate principal amount of $54,000,000 (the "2006 Series B Bonds"), issued pursuant to an Indenture of Trust dated as of October 1, 2006 (the "2006 Series B Indenture") between the Issuer and Deutsche Bank Trust Company Americas (the "2006 Series B Trustee"), as Trustee, Paying Agent and Bond Registrar, as the same has been amended and restated as of September 1, 2008, and (ii) Environmental Facilities Revenue Bonds, 2008 Series A (Kentucky Utilities Company Project), in the aggregate principal amount of $77,947,405 (the "Bonds") issued pursuant to an Indenture of Trust dated as of August 1, 2008 (the "2008 Series A Indenture" and, collectively with the 2006 Series B Indenture, the "Indentures") between the Issuer and Deutsche Bank Trust Company Americas (the "2008 Series A Trustee" and, collectively with the 2006 Series B Trustee, the "Trustee"), as Trustee, Paying Agent and Bond Registrar.

Pursuant to separate Loan Agreements by and between Kentucky Utilities Company (the "Company") and the Issuer, dated as of October 1, 2006 (as the same have been amended and restated as of September 1, 2008 pursuant to an ordinance of the Issuer adopted October 28, 2008), with respect to the 2006 Series B Bonds (the "2006 Series B Loan Agreement"), and August 1, 2008 (pursuant to an ordinance of the Issuer adopted September 23, 2008) with respect to the 2008 Series A Bonds (the "2008 Series A Loan Agreement" and, collectively with the 2006 Series B Loan Agreement, the "Loan Agreements"), proceeds from the sale of the Bonds, other than accrued interest, if any, paid by the initial purchasers thereof, were loaned by the Issuer to the Company. The Loan Agreements are separate undertakings by and between the Company and the Issuer.

The Company will continue to repay the loans under the 2006 Series B Loan Agreement and the 2008 Series A Loan Agreement by making payments to the applicable Trustee in sufficient amounts to pay the principal of and interest and any premium on, and purchase price of, the applicable series of Bonds. See "Summary of the Loan Agreement — General." Pursuant to the applicable Indenture, the Issuer's rights under the applicable Loan Agreement (other than with respect to certain indemnification and expense payments and notification rights) were assigned to the applicable Trustee as security for the applicable series of Bonds.

The proceeds of the 2006 Series B Bonds were applied to pay and discharge all of the $54,000,000 outstanding principal amount of County of Carroll, Kentucky, Collateralized Solid

Waste Disposal Facilities Revenue Bonds (Kentucky Utilities Company Project) 1994 Series A," dated November 23, 1994, previously issued by the Issuer to finance certain solid waste disposal facilities owned by the Company (the "2006 Series B Project"). The proceeds of the 2008 Series A Bonds were applied to (i) finance the acquisition, construction, installation and equipping of certain solid waste disposal facilities owned by the Company in the amount of $18,026,265 and (ii) pay and discharge all of the $13,266,950 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2005 Series A (Kentucky Utilities Company Project), $13,266,950 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2005 Series B (Kentucky Utilities Company Project), $16,693,620 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2006 Series A (Kentucky Utilities Company Project) and $16,693,620 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2006 Series C (Kentucky Utilities Company Project), all previously issued by the Issuer to finance certain solid waste disposal facilities (collectively, the "2008 Series A Project") owned by the Company. For information regarding the Project, see "The Project."

The Company is an operating subsidiary of E.ON U.S. LLC (formerly known as LG&E Energy LLC) and E.ON AG (the "Parents"). See "Appendix A — Kentucky Utilities Company — Financial Statements and Additional Information." The Parents have no obligation to make any payments due under the Loan Agreements or any other payments of principal, interest, premium or purchase price of the Bonds.

The Bonds are being converted to bear interest at a Weekly Rate, but may be subsequently converted again to bear interest at a Daily Rate, a Weekly Rate, a Flexible Rate, a Semi-Annual Rate, an Annual Rate, a Long Term Rate or with respect to the 2006 Series B Bonds, a Dutch Auction Rate. **This Reoffering Circular pertains only to the Bonds during such period of time that they bear interest at the Weekly Rate.**

The Bonds are special and limited obligations of the Issuer, and the Issuer's obligation to pay the principal of and interest and any premium on, and purchase price of, each series of the Bonds is limited solely to the revenues and other amounts received by the applicable Trustee under the applicable Indenture pursuant to the applicable Loan Agreement (and the applicable Letter of Credit (as defined below). The Bonds do not constitute an indebtedness, general obligation or pledge of the faith and credit or taxing power of the Issuer, the Commonwealth of Kentucky or any political subdivision thereof. The Bonds are not entitled to the benefits of any financial guaranty insurance policies.

Concurrently with, and as a condition to, the conversion and reoffering of the Bonds, the Company will cause to be delivered separate irrevocable transferable direct pay letters of credit (the "Letters of Credit") with respect to each of the 2006 Series B Bonds and the 2008 Series A Bonds, issued by Commerzbank AG, New York Branch (the "Bank"), to provide for the timely payment of principal of and accrued interest (calculated for at least 45 days at the maximum rate of 15% per annum) on, and purchase price of, the Bonds. The Company will be required to reimburse the Bank for all amounts drawn by the Trustee under the Letters of Credit pursuant to the terms of separate Reimbursement Agreements, to be dated as of December 19, 2008 (collectively, the "Reimbursement Agreement"), with respect to each of the 2006 Series B Bonds and the 2008 Series A Bonds, between the Company and the Bank. Each Letter of Credit will expire on December 18, 2009, unless extended or earlier terminated.

Upon expiration of a Letter of Credit or any Alternate Credit Facility, the related series of Bonds will be subject to mandatory tender for purchase. See "Summary of the Bonds — Mandatory Purchases of Bonds — Mandatory Purchase upon Delivery, Cancellation, Substitution, Extension, Termination or Expiration of Any Credit Facility or Replacement with an Alternate Credit Facility." As used in this Reoffering Circular, "Bank" or "Credit Facility Issuer" refers to the Bank as the issuer of the applicable Letter of Credit and any other issuer of any Alternate Credit Facility delivered in accordance with the applicable Indenture; "Letter of Credit" or "Credit Facility" means the applicable Letter of Credit delivered under the applicable Indenture and, as applicable, any Alternate Credit Facility which may be subsequently delivered in accordance with such Indenture; and "Reimbursement Agreement" refers to the applicable initial Reimbursement Agreement under which the related Letter of Credit is provided and any subsequent agreement entered into between the Company and any other party in connection with the delivery of any Alternate Credit Facility.

Banc of America Securities LLC will be appointed under the Indentures to serve as Remarketing Agent for the Bonds. Any Remarketing Agent may resign or be removed and a successor Remarketing Agent may be appointed in accordance with the terms of the applicable Indenture and the applicable Remarketing Agreement for the Bonds between such Remarketing Agent and the Company.

Brief descriptions of the Company, the Issuer, the Bonds, the Loan Agreements, the Indentures, the Letters of Credit and the Reimbursement Agreements are included in this Reoffering Circular. Appendix A to this Reoffering Circular has been furnished by the Company. The Issuer and Bond Counsel assume no responsibility for the accuracy or completeness of such Appendix A or such information. Appendix B to this Reoffering Circular contains the opinions of Bond Counsel delivered on the dates on which each series of the Bonds were initially issued, and the proposed forms of opinions of Bond Counsel to be delivered in connection with the conversion of each series of the Bonds to the Weekly Rate. Appendix C to this Reoffering Circular contains information about the Bank. The Issuer and Bond Counsel assume no responsibility for the accuracy or completeness of such Appendix C or such information. Such descriptions and information do not purport to be complete, comprehensive or definitive and are not to be construed as a representation or a guaranty of accuracy or completeness. All references herein to the documents are qualified in their entirety by reference to such documents, and references herein to a series of Bonds are qualified in their entirety by reference to the definitive form thereof included in the applicable Indenture. Copies of the Loan Agreements, the Indentures, the Letters of Credit and the Reimbursement Agreements will be available for inspection at the principal corporate trust office of the Trustee party thereto. Certain information relating to The Depository Trust Company ("DTC") and the book-entry-only system has been furnished by DTC. All statements herein are qualified in their entirety by reference to each such document and, with respect to the enforceability of certain rights and remedies, to laws and principles of equity relating to or affecting generally the enforcement of creditors' rights.

The Projects

2006 Series B Project

The 2006 Series B Project has been completed, placed in operation and is the property of the Company and consists of certain solid waste disposal facilities at the Company's Ghent Generating Station located in Carroll County, Kentucky for the collection, storage, treatment processing and final disposal of solid wastes.

2008 Series A Project

The 2008 Series A Project consists of the Construction Project and the Refunding Project.

Construction Project. The "Construction Project" consists of certain solid waste disposal facilities at the Company's Ghent Generating Station, Unit 1, located in Carroll County, Kentucky for the collection, storage, treatment and final disposal of solid wastes ("Ghent Generating Station"). The Company has begun construction and fabrication of the Construction Project. The Kentucky Public Service Commission has issued a Certificate of Convenience and Necessity ("CCN") that authorizes construction of the Construction Project. When constructed, the Construction Project will be the property of the Company.

Refunding Project. The "Refunding Project" consists of certain solid waste disposal facilities at the Ghent Generating Station for the collection, storage, treatment and final disposal of solid wastes. The Refunding Project has been completed, placed in operation and Completion Certificates in respect thereof have been issued. The Refunding Project has and will contribute to the collection, storage, treatment, processing and final disposal of solid wastes.

Separate Series

The 2006 Series B Bonds and the 2008 Series A Bonds are separate series and optional or mandatory redemption of any series may be made in the manner described below without the redemption of the other series. Similarly, a default under one of the series of Bonds or one of the Loan Agreements will not necessarily constitute a default under the other series of Bonds or Loan Agreements. Each series of Bonds can bear interest at an Interest Rate Mode different from the Interest Rate Mode borne by the other series of Bonds. Unless specifically otherwise noted, any discussion herein and under the captions "Summary of the Bonds," "The Letter of Credit," "Security; Limitation of Liens," "Summary of the Loan Agreement," "Summary of the Indenture," "Enforceability of Remedies" and "Tax Treatment" applies equally, but separately, to the 2006 Series B Bonds and the 2008 Series A Bonds.

As used herein under such captions with respect to the 2006 Series B Bonds, the term "Project" shall mean the 2006 Series B Project, the term "Bonds" shall mean the 2006 Series B Bonds, the term "Loan Agreement" shall mean the 2006 Series B Loan Agreement pursuant to which the Issuer loaned the proceeds from the sale of the 2006 Series B Bonds to the Company, the term "Indenture" shall mean the 2006 Series B Indenture, the term "Remarketing Agent" shall mean Banc of America Securities LLC, the terms "Trustee" and "Tender Agent" shall mean the 2006 Series B Trustee and the term "Letter of Credit" shall mean the Letter of Credit delivered to the 2006 Series B Trustee.

As used herein under such captions with respect to the 2008 Series A Bonds, the term "Project" shall mean the 2008 Series A Project, the term "Bonds" shall mean the 2008 Series A Bonds, the term "Loan Agreement" shall mean the 2008 Series A Loan Agreement pursuant to which the Issuer loaned the proceeds from the sale of the 2008 Series A Bonds to the Company, the term "Indenture" shall mean the 2008 Series A Indenture, the term "Remarketing Agent" shall mean Banc of America Securities LLC, the terms "Trustee" and "Tender Agent" shall mean the 2008 Series A Trustee and the term "Letter of Credit" shall mean the Letter of Credit delivered to the 2008 Series A Trustee.

The Issuer

The Issuer is a public body corporate and politic duly created and existing as a county and political subdivision under the Constitution and laws of the Commonwealth of Kentucky. The Issuer is authorized by Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (collectively, the "Act") to (a) convert and reoffer the Bonds and (b) amend and restate and continue to perform its obligations under the Loan Agreement and the Indenture. The Issuer, through its legislative body, the Fiscal Court, has adopted one or more ordinances authorizing the issuance of the Bonds and the execution and delivery of the related documents.

THE BONDS ARE SPECIAL AND LIMITED OBLIGATIONS PAYABLE SOLELY AND ONLY FROM CERTAIN SOURCES, INCLUDING AMOUNTS TO BE RECEIVED BY THE TRUSTEE FROM THE APPLICABLE LETTER OF CREDIT AND BY OR ON BEHALF OF THE ISSUER UNDER THE APPLICABLE LOAN AGREEMENT. THE BONDS DO NOT CONSTITUTE AN INDEBTEDNESS, GENERAL OBLIGATION OR PLEDGE OF THE FAITH AND CREDIT OR TAXING POWER OF THE ISSUER, THE COMMONWEALTH OF KENTUCKY OR ANY POLITICAL SUBDIVISION THEREOF, AND DO NOT GIVE RISE TO A PECUNIARY LIABILITY OF THE ISSUER OR A CHARGE AGAINST ITS GENERAL CREDIT OR TAXING POWERS.

Summary of the Bonds

Although each series of Bonds is an entirely separate issue and has been issued under a separate Indenture, each Indenture contains substantially the same terms and provisions except as otherwise noted below.

General

The Bonds will be issued in the aggregate principal amounts set forth on the cover page of this Reoffering Circular. The 2006 Series B Bonds will mature on October 1, 2034. The 2008 Series A Bonds will mature on February 1, 2032. The Bonds are also subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption prior to maturity as described in this Reoffering Circular.

The 2006 Series B Bonds currently bear interest at a Dutch Auction Rate, and the 2008 Series A Bonds currently bear interest at a Flexible Rate. Pursuant to the terms and provisions of the Indentures summarized below, the Company has exercised its option, effective December 19, 2008 (the "Conversion Date"), to convert the interest rate on the Bonds to a Weekly Rate. From and after the Conversion Date and reoffering of the Bonds, the Bonds will bear interest at a

Weekly Rate and will be payable on the first Business Day of each calendar month, commencing on January 2, 2009. The Bonds will continue to bear interest at the Weekly Rate until a Conversion to another Interest Rate Mode or until the maturity or redemption of the Bonds. The permitted Interest Rate Modes for the Bonds are (i) the "Flexible Rate," (ii) the "Daily Rate," (iii) the "Weekly Rate," (iv) the "Semi-Annual Rate," (v) the "Annual Rate," (vi) the "Long Term Rate" and (vii) with respect to the 2006 Series B Bonds, the "Dutch Auction Rate." Changes in the Interest Rate Mode will be effected, and notice of such changes will be given, as described below in "—Conversion of Interest Rate Modes and Changes of Long Term Rate Periods."

During each Rate Period for an Interest Rate Mode (other than the Dutch Auction Rate Mode with respect to the 2006 Series B Bonds), the interest rate or rates for the Bonds in that Interest Rate Mode, and Flexible Rate Periods for Bonds accruing interest at a Flexible Rate, will be determined by the Remarketing Agent in accordance with the Indenture; provided that the interest rate or rates borne by any Bonds may not exceed the lesser of (i) the maximum interest rate permitted by applicable law or (ii) 15% per annum. With respect to the 2006 Series B Bonds, the interest rate for the Bonds that bear interest at a Dutch Auction Rate will be determined in accordance with the procedures established pursuant to the Indenture.

Interest on the Bonds which bear interest at a Flexible Rate, Daily Rate or Weekly Rate will be computed on the basis of a year of 365 or 366 days, as appropriate, and paid for the actual number of days elapsed. Interest on the Bonds which bear interest at a Semi-Annual Rate, Annual Rate or Long Term Rate will be computed on the basis of a 360-day year, consisting of twelve 30-day months. With respect to the 2006 Series B Bonds, interest on the Bonds which bear interest at a Dutch Auction Rate will be computed on the basis of a 360-day year for the actual number of days elapsed. Interest payable on any Interest Payment Date will be payable to the registered owner of the Bond as of the Record Date for such payment; provided that in the case of Bonds bearing interest at the Flexible Rate, interest will be payable to the registered owner of such Bond on the Interest Payment Date therefor. The Record Date, in the case of interest accrued at a Daily Rate or Weekly Rate, will be the close of business on the Business Day immediately preceding each Interest Payment Date, in the case of interest accrued at a Semi-Annual Rate, Annual Rate or Long Term Rate, will be the close of business on the fifteenth day (whether or not a Business Day) of the month preceding each Interest Payment Date, and with respect to the 2006 Series B Bonds, in the case of interest accrued at a Dutch Auction Rate, will be the close of business on the second Business Day preceding each Interest Payment Date.

The Bonds initially will be issued solely in book-entry-only form through DTC (or its nominee, Cede & Co.). So long as the Bonds are held in the book-entry-only system, DTC or its nominee will be the registered owner or holder of the Bonds for all purposes of the Indenture, the Bonds and this Reoffering Circular. See "— Book-Entry-Only System" below. Individual purchases of book-entry interests in the Bonds will be made in book-entry-only form in (i) denominations of $100,000 or any integral multiple thereof, if bearing interest at the Daily Rate or the Weekly Rate, (ii) denominations of $100,000 or any integral multiple of $5,000 in excess of $100,000, if bearing interest at Flexible Rates, (iii) denominations of $5,000 and integral multiples thereof, if bearing interest at the Semi-Annual Rate, the Annual Rate or the Long Term Rate, or (iv) with respect to the 2006 Series B Bonds, denominations of $25,000 and integral multiples thereof, if bearing interest at a Dutch Auction Rate; provided, that with respect to the

2008 Series A Bonds, (i) if such 2008 Series A Bonds bear interest at the Daily Rate or the Weekly Rate, one 2008 Series A Bond may be in the denomination of, or include an additional $47,405 and (ii) if such 2008 Series A Bonds bear interest at the Semi-Annual Rate, the Annual Rate, the Long Term Rate or the Flexible Rate, one 2008 Series A Bond may be in the denomination of, or include an additional $2,405.

Except as otherwise described below for Bonds held in DTC's book-entry-only system, the principal or redemption price of the Bonds is payable at the designated corporate trust office in New York, New York, of the Trustee, as paying agent (the "Paying Agent"). Except as otherwise described below for Bonds held in DTC's book-entry-only system, interest on the Bonds is payable by check mailed to the owner of record; provided that interest payable on each Bond will be payable in immediately available funds by wire transfer within the continental United States or by deposit into a bank account maintained with the Trustee or a Paying Agent (i) if the Interest Rate Mode is the Daily Rate, the Weekly Rate or the Flexible Rate or, with respect to the 2006 Series B Bonds, the Dutch Auction Rate or (ii) at the written request of any owner of record holding at least $1,000,000 aggregate principal amount of the Bonds, if the Interest Rate Mode is the Semi-Annual Rate, Annual Rate or Long Term Rate, received by the Trustee, as bond registrar (the "Bond Registrar"), at least one Business Day prior to any Record Date. Except as otherwise described below for Bonds held in DTC's book-entry-only system, if the Interest Rate Mode is the Flexible Rate, interest payable on each Bond will be paid only upon presentation and surrender of such Bond.

Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the principal office of the Bond Registrar, accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond (i) during the fifteen days before any mailing of a notice of redemption of Bonds, (ii) after such Bond has been called for redemption or (iii) for which a registered owner has submitted a demand for purchase (see "— Purchases of Bonds on Demand of Owner" below), or which has been purchased (see "— Payment of Purchase Price" below). Registration of transfers and exchanges will be made without charge to the registered owners of Bonds, except that the Bond Registrar may require any registered owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

The Bonds Are Not Insured

Upon the conversion of the Bonds to a Weekly Rate on the Conversion Date and the delivery of the Letter of Credit, the Financial Guaranty Insurance Policy (the "Bond Insurance Policy") issued by Ambac Assurance Corporation ("Ambac") with respect to the 2006 Series B Bonds on February 23, 2007 will have been irrevocably surrendered and cancelled. The 2008 Series A Bonds are currently not entitled to the benefits of any financial guaranty insurance policy. The Bonds described in this Reoffering Circular are not insured, and holders thereof will have no recourse to, under or against any bond insurance policy or bond insurer, including the aforementioned Bond Insurance Policy issued by Ambac.

Tender Agent

Owners may tender their Bonds, and in certain circumstances will be required to tender their Bonds, to the Tender Agent for purchase at the times and in the manner described herein under "— Summary of Certain Provisions of the Bonds," "— Purchases of Bonds on Demand of Owner" and "— Mandatory Purchases of Bonds." So long as the Bonds are held in DTC's book-entry-only system, the Trustee will act as Tender Agent under the Indenture. Any successor Tender Agent appointed pursuant to the Indenture will also be a Paying Agent.

Remarketing Agent

Banc of America Securities LLC will act as the Remarketing Agent with respect to the Bonds (the "Remarketing Agent"). The Remarketing Agent may resign or be removed and a successor Remarketing Agent may be appointed in accordance with the terms of the applicable Indenture and the applicable Remarketing Agreement for the Bonds between the Remarketing Agent and the Company.

Special Considerations Relating to the Remarketing Agent

The Remarketing Agent is paid by the Company.

The Remarketing Agent's responsibilities include determining the interest rate from time to time and remarketing Bonds that are optionally or mandatorily tendered by the owners thereof (subject, in each case, to the terms of the Remarketing Agreement), all as further described herein. The Remarketing Agent is appointed by the Issuer at the request of the Company and paid by the Company for its services. As a result, the interests of the Remarketing Agent may differ from those of existing holders and potential purchasers of Bonds.

The Remarketing Agent routinely purchases bonds for its own account.

The Remarketing Agent acts as remarketing agent for a variety of variable rate demand obligations and, in its sole discretion, routinely purchases such obligations for its own account in order to achieve a successful remarketing of the obligations (i.e., because there are otherwise not enough buyers to purchase the obligations) or for other reasons. The Remarketing Agent is permitted, but not obligated, to purchase tendered Bonds for its own account and, if it does so, it may cease doing so at any time without notice. The Remarketing Agent may also make a market in the Bonds by routinely purchasing and selling Bonds other than in connection with an optional or mandatory tender and remarketing. Such purchases and sales may be at or below par. However, the Remarketing Agent is not required to make a market in the Bonds. The Remarketing Agent may also sell any Bonds it has purchased to one or more affiliated investment vehicles for collective ownership or enter into derivative arrangements with affiliates or others in order to reduce its exposure to the Bonds. The purchase of Bonds by the Remarketing Agent may create the appearance that there is greater third party demand for the Bonds in the market than is actually the case. The practices described above also may result in fewer Bonds being tendered in a remarketing.

<u>Bonds may be offered at different prices on any date.</u>

As more fully described under the caption "— Determination of Interest Rates for Interest Rate Modes," the Remarketing Agent shall determine the minimum rate of interest per annum which in the opinion of the Remarketing Agent, would be necessary on and as of such day to remarket the Bonds in a secondary market transaction at a price equal to the principal amount thereof plus accrued interest thereon, if any, provided that such rate of interest shall not exceed 15% per annum. The interest rate will reflect, among other factors, the level of market demand for the Bonds (including whether the Remarketing Agent is willing to purchase Bonds for its own account). There may or may not be Bonds tendered and remarketed on a day that the rate on the Bonds are set, the Remarketing Agent may or may not be able to remarket any Bonds tendered for purchase on such date at par and the Remarketing Agent may sell Bonds at varying prices to different investors on such date or any other date. The Remarketing Agent is not obligated to advise purchasers in a remarketing if it does not have third party buyers for all of the Bonds at the remarketing price. In the event the Remarketing Agent owns any Bonds for its own account, it may, in its sole discretion in a secondary market transaction outside the tender process, offer such Bonds on any date, including the day that the rate on the Bonds are set, at a discount to par to some investors.

<u>The ability to sell the Bonds other than through the tender process may be limited.</u>

The Remarketing Agent may buy and sell Bonds other than through the tender process. However, it is not obligated to do so and may cease doing so at any time without notice and may require holders that wish to tender their Bonds to do so through the Trustee with appropriate notice. Thus, investors who purchase the Bonds, whether in a remarketing or otherwise, should not assume that they will be able to sell their Bonds other than by tendering the Bonds in accordance with the tender process.

Certain Definitions

As used herein, each of the following terms will have the meaning indicated.

"*Alternate Credit Facility*" means an irrevocable letter of credit, a municipal bond insurance policy, a surety bond, a line or lines of credit, a guarantee or other similar agreement or agreements or any other agreement or agreements used to provide liquidity or credit support for the Bonds, satisfactory to the Company and the Remarketing Agent and containing administrative provisions reasonably satisfactory to the Trustee, issued and delivered to the Trustee in accordance with the Indenture.

"*Annual Rate Period*" means the period beginning on, and including, the Conversion Date to the Annual Rate and ending on, and including, the day next preceding the second Interest Payment Date thereafter, and each successive twelve-month period (or portion thereof) thereafter until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Beneficial Owner*" means the person in whose name a Bond is recorded as such by the respective systems of DTC and each DTC Participant (as defined herein) or the registered holder of such Bond if such Bond is not then registered in the name of Cede & Co.

"*Business Day*" means any day other than a Saturday or Sunday or legal holiday or a day on which banking institutions located in the City of New York, New York, or the New York Stock Exchange or banking institutions in the city in which the principal office of the Trustee, the Bond Registrar, the Tender Agent, the Paying Agent, the Auction Agent with respect to the 2006 Series B Bonds, the Company, the Credit Facility Issuer or the Remarketing Agent is located are authorized by law or executive order to close.

"*Conversion*" means any conversion from time to time in accordance with the terms of the Indenture of the Bonds from one Interest Rate Mode to another Interest Rate Mode.

"*Conversion Date*" means initially the date of original issuance of the Bonds, and thereafter means the date on which any Conversion becomes effective.

"*Credit Facility*" means an irrevocable direct pay letter of credit or other credit enhancement or liquidity support facility, or any combination thereof, delivered to and in favor of the Trustee for the benefit of the owners of the Bonds pursuant to the Indenture and designated as a "Credit Facility" under the Indenture, and includes the Initial Credit Facility or any Alternate Credit Facility delivered to the Trustee pursuant to the Indenture.

"*Credit Facility Issuer*" means the Initial Credit Facility Issuer and the issuer of any Credit Facility or Alternate Credit Facility subsequently in effect.

"*Daily Rate Period*" means the period beginning on, and including, the Conversion Date to the Daily Rate and ending on and including the day preceding the next Business Day and each period thereafter beginning on and including a Business Day and ending on and including the day preceding the next succeeding Business Day until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Dutch Auction Rate*" means, with respect to the 2006 Series B Bonds, the rate of interest to be borne by the Bonds during each Dutch Auction Rate Period determined in accordance with the 2006 Series B Indenture.

"*Dutch Auction Rate Period*" means, with respect to the 2006 Series B Bonds, each period during which the 2006 Series B Bonds bear interest at a Dutch Auction Rate.

"*Flexible Rate*" means the Interest Rate Mode for the Bonds in which the interest rate for each Bond is determined with respect to such Bond during each Flexible Rate Period applicable to that Bond, as provided in the Indenture.

"*Flexible Rate Period*" means with respect to any Bond, each period (which may be from one day to 270 days, or such lower maximum number of days as is then permitted under the Indenture) determined for such Bond, as provided in the Indenture.

"*Initial Credit Facility*" means the irrevocable direct pay letter of credit issued by the Initial Credit Facility Issuer to the Trustee with respect to the Bonds on the Conversion Date.

"*Initial Credit Facility Issuer*" means Commerzbank AG, New York.

"*Interest Payment Date*" means (i) if the Interest Rate Mode is the Daily Rate or the Weekly Rate, the first Business Day of each calendar month, (ii) if the Interest Rate Mode is the Flexible Rate, for each Bond the last day of each Flexible Rate Period for such Bond (or if such day is not a Business Day, the next succeeding Business Day), (iii) if the Interest Rate Mode is the Semi-Annual Rate, the Annual Rate or the Long Term Rate, June 1 and December 1, and, in the case of the Long Term Rate, also the Conversion Date or the effective date of a change to a new Long Term Rate Period, (iv) with respect to the 2006 Series B Bonds, if the Interest Rate Mode is the Dutch Auction Rate Period, the dates determined in accordance with the terms of the Indenture or (v) with respect to any Bond, the Conversion Date (including the date of a failed Conversion) or the effective date of a change to a new Long Term Rate Period for such Bond. In any case, the final Interest Payment Date will be the maturity date of the Bonds.

"*Interest Period*" means for all Bonds (or for any Bond if the Interest Rate Mode is the Flexible Rate) the period from and including each Interest Payment Date to and including the day immediately preceding the next Interest Payment Date, provided, however that the first Interest Period for the Bonds will begin on (and include) the date of issuance of the Bonds and the final Interest Period will end on September 30, 2034, with respect to the 2006 Series B Bonds, or January 31, 2032, with respect to the 2008 Series A Bonds.

"*Interest Rate Mode*" means the Flexible Rate, the Daily Rate, the Weekly Rate, the Semi-Annual Rate, the Annual Rate, the Long Term Rate for each series of the Bonds and, with respect to the 2006 Series B Bonds, the Dutch Auction Rate.

"*Long Term Rate Period*" means any period established by the Company as hereinafter set forth under "— Determination of Interest Rates for Interest Rate Modes — Long Term Rates and Long Term Rate Periods" and beginning on, and including, the Conversion Date to the Long Term Rate and ending on, and including, the day preceding the last Interest Payment Date for such period and, thereafter, each successive period of the same duration as the Long Term Rate Period previously established until the day preceding the earliest of the change to a different Long Term Rate Period, the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Maximum Rate*" means the lesser of (i) the maximum interest rate permitted by applicable law or (ii) 15%.

"*Prevailing Market Conditions*" means, without limitation, the following factors: existing short-term or long-term market rates for securities, the interest on which is excluded from gross income for federal income tax purposes; indexes of such short-term or long-term rates and the existing market supply and demand for securities bearing such short-term or long-term rates; existing yield curves for short-term or long-term securities for obligations of credit quality comparable to the Bonds, the interest on which is excluded from gross income for federal income tax purposes; general economic conditions; industry economic and financial conditions that may affect or be relevant to the Bonds; and such other facts, circumstances and conditions as the Remarketing Agent, in its sole discretion, determines to be relevant.

"*Purchase Date*" means any date on which Bonds are to be purchased on the demand of the registered owners thereof or are subject to mandatory purchase as described in the Indenture.

"*Reimbursement Agreement*" means the Reimbursement Agreement, to be dated as of December 19, 2008, between the Company and the Initial Credit Facility Issuer, as the same may be amended from time to time, and any other agreement between the Company and a Credit Facility Issuer, setting forth the obligations of the Company to such Credit Facility Issuer arising out of any payments under such Credit Facility and which provides that it will be deemed to be a Reimbursement Agreement for the purpose of the Indenture.

"*Semi-Annual Rate Period*" means any period beginning on, and including, the Conversion Date to the Semi-Annual Rate, and ending on, and including, the day preceding the first Interest Payment Date thereafter and each successive six-month period thereafter beginning on and including an Interest Payment Date and ending on and including the day next preceding the next Interest Payment Date until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Weekly Rate Period*" means, (i) with respect to the 2006 Series B Bonds, the period beginning on, and including the Conversion Date to the Weekly Rate, and ending on, and including, the next Thursday, and thereafter the period beginning on, and including any Friday and ending on, and including, the earliest of the next Thursday, the day preceding the Conversion to a different Interest Rate Mode or the maturity of the Bonds, and (ii) with respect to the 2008 Series A Bonds, the period beginning on, and including, the Conversion Date to the Weekly Rate, and ending on, and including, the next Wednesday, and thereafter the period beginning on, and including, any Thursday and ending on, and including, the earliest of the next Wednesday, the day preceding the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

Summary of Certain Provisions of the Bonds

The following table summarizes, for each of the permitted Interest Rate Modes (except the Dutch Auction Rate with respect to the 2006 Series B Bonds): the dates on which interest will be paid (*Interest Payment Dates*); the dates on which each interest rate will be determined (*Interest Rate Determination Dates*); the period of time (*Interest Rate Periods*) each interest rate will be in effect (provided that the initial Interest Rate Period for each Interest Rate Mode may begin on a different date from that specified, which date will be the Conversion Date or the date of a change in the Long Term Rate, as applicable); the dates on which registered owners may tender their Bonds for purchase to the Tender Agent and the notice requirements therefor (provided that while the Bonds are held in book-entry-only form, all notices of tender for purchase will be given by Beneficial Owners in the manner described below under "Purchases of Bonds on Demand of Owner — Notice Required for Purchases") (*Purchase on Demand of Owner; Required Notice*); the dates on which Bonds are subject to mandatory tender for purchase (*Mandatory Purchase Dates*); the redemption provisions applicable to the Bonds (*Redemption*); the notice requirements for redemption and mandatory tender for purchase (*Notices of Redemption and Mandatory Purchases*); and the manner by which registered owners will receive payments of principal, interest, redemption price and purchase price (*Manner of Payment*). All times stated are New York City time. Provisions relating to the Bonds while they bear interest at a Dutch Auction Rate, with respect to the 2006 Series B Bonds, will be determined in accordance with auction procedures established at the time of conversion to the Dutch Auction Rate.

	FLEXIBLE RATE	DAILY RATE	WEEKLY RATE
Interest Payment Dates	With respect to any Bond, the last day of each Flexible Rate Period (or if such day is not a Business Day, the next succeeding Business Day).	The first Business Day of each calendar month.	The first Business Day of each calendar month.
Interest Rate Determination Dates	For each Bond, not later than 12:00 noon on the first day of each Flexible Rate Period for such Bond.	Not later than 9:30 a.m. on each Business Day.	Not later than 4:00 p.m. on the day preceding the first day of each Weekly Rate Period or, if not a Business Day, on the next preceding Business Day.
Interest Rate Periods	For each Bond, each Flexible Rate Period will be of a duration designated by the Remarketing Agent of one day to 270 days (or lower maximum number as specified in the Indenture); must end on a day immediately preceding a Business Day.	From and including each Business Day to but not including the next Business Day.	From and including each Friday to and including the following Thursday for the 2006 Series B Bonds. From and including each Thursday to and including the following Wednesday for the 2008 Series A Bonds.
Purchase on Demand of Owner; Required Notice*	No purchase on demand of the owner.	Any Business Day; by written or telephonic notice, promptly, with respect to the 2006 Series B Bonds, or immediately, with respect to the 2008 Series A Bonds, confirmed in writing, to the Tender Agent by 10:00 a.m. on such Business Day.	Any Business Day; by written notice to the Tender Agent not later than 5:00 p.m. on a Business Day at least seven days prior to the Purchase Date.
Mandatory Purchase Dates	Any Conversion Date; and with respect to each Bond, on each Interest Payment Date for such Bond; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.
Redemption	Optional at par on any Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day (other than extraordinary optional redemption as a result of damage, destruction or condemnation which will be on an Interest Payment Date).	Optional, Extraordinary Optional and Mandatory at par on any Business Day.	Optional, Extraordinary Optional and Mandatory at par on any Business Day.
Notices of Conversion, Redemption and Mandatory Purchases*	Not fewer than 15 days (30 days notice of Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days. No notice of mandatory purchase following end of each Flexible Rate Period.	Not fewer than 15 days (30 days notice of Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days.	Not fewer than 15 days (30 days notice of Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days.
Manner of Payment*	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.

* So long as DTC or its nominee is the registered owner of the Bonds, notices of redemption and mandatory purchases shall be sent to Cede & Co., payments of principal, redemption and purchase price of and interest on the Bonds will be paid through the facilities of DTC and notices of mandatory purchase may be given not less than five days prior to the Purchase Date. See "— Book-Entry-Only System" below.

	SEMI-ANNUAL	**ANNUAL**	**LONG TERM**
Interest Payment Date	Each June 1 and December 1.	Each June 1 and December 1.	Each June 1 and December 1; any Conversion Date; and the effective date of any change to a new Long Term Rate Period.
Interest Rate Determination Dates	Not later than 2:00 p.m. on the Business Day preceding the first day of the Semi-Annual Rate Period.	Not later than 12:00 noon on the Business Day preceding the first day of the Annual Rate Period.	Not later than 12:00 noon on the Business Day preceding the first day of the Long Term Rate Period.
Interest Rate Periods	Each six-month period from and including each June 1 and December 1 to and including the day preceding the next Interest Payment Date.	Each period from and including the Conversion Date to the Annual Rate to and including the day immediately preceding the second Interest Payment Date thereafter and each successive twelve month period thereafter.	Each period designated by the Company of more than one year in duration and which is an integral multiple of six months, from and including the first day of such period (June 1 and December 1) to and including the day immediately preceding the last Interest Payment Date for that period.
Purchase on Demand of Owner; Required Notice*	On any Interest Payment Date; by written notice to the Tender Agent on any Business Day not later than the fifteenth day prior to the Purchase Date.	On the final Interest Payment Date for the Annual Rate Period; by written notice to the Tender Agent on any Business Day not later than the fifteenth day prior to the Purchase Date.	On the final Interest Payment Date for the Long Term Rate Period; by written notice to the Tender Agent on a Business Day not later than the fifteenth day prior to the Purchase Date.
Mandatory Purchase Dates	Any Conversion Date; the first Business Day after the end of each Semi-Annual Rate Period; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; the first Business Day after the end of each Annual Rate Period; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; the first Business Day after the end of each Long Term Rate Period; the effective date of a change of Long Term Rate Period; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.
Redemption	Optional at par on any Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day (other than extraordinary optional redemption as a result of damage, destruction or condemnation which will be on an Interest Payment Date).	Optional at par on the final Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day.	Optional at times and prices dependent on the length of the Long Term Rate Period; Extraordinary Optional and Mandatory at par, on any Business Day.
Notices of Conversion, Redemption and Mandatory Purchases*	Not fewer than 15 days (30 days for notice of Conversion or redemption) or greater than 45 days.	Not fewer than 15 days (30 days for notice of Conversion or redemption) or greater than 45 days.	Not fewer than 15 days (30 days for notice of Conversion or redemption) or greater than 45 days.
Manner of Payment*	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner, of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner, of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner, of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.

* So long as DTC or its nominee is the registered owner of the Bonds, notices of redemption and mandatory purchases shall be sent to Cede & Co., payments of principal, redemption and purchase price of and interest on the Bonds will be paid through the facilities of DTC and notices of mandatory purchase may be given not less than five days prior to the Purchase Date. See "— Book-Entry-Only System" below.

Determination of Interest Rates for Interest Rate Modes

Daily Rate. If the Interest Rate Mode for the Bonds is the Daily Rate, the interest rate on the Bonds for any Business Day will be the rate established by the Remarketing Agent no later than 9:30 a.m. (New York City time) on each Business Day as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such Business Day at a price equal to the principal amount thereof, plus accrued interest, if any, thereon. For any day which is not a Business Day or if the Remarketing Agent does not give notice of a change in the interest rate, the interest rate on the Bonds will be the interest rate in effect for the immediately preceding Business Day.

Weekly Rate. If the Interest Rate Mode for the Bonds is the Weekly Rate, the interest rate on the Bonds for a particular Weekly Rate Period will be the rate established by the Remarketing Agent no later than 4:00 p.m. (New York City time) on the day preceding such Weekly Rate Period or, if such day is not a Business Day, on the next preceding Business Day, as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof, plus accrued interest, if any, thereon.

Flexible Rates and Flexible Rate Periods. If the Interest Rate Mode for the Bonds is the Flexible Rate, the interest rate on a Bond for a specific Flexible Rate Period will be the rate established by the Remarketing Agent no later than 12:00 noon (New York City time) on the first day of that Flexible Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell such Bond on that day at a price equal to the principal amount thereof. Each Flexible Rate Period applicable for a Bond will be determined separately by the Remarketing Agent on or prior to the first day of such Flexible Rate Period as being the Flexible Rate Period permitted under the Indenture which, in the judgment of the Remarketing Agent, taking into account then Prevailing Market Conditions, will, with respect to such Bond, ultimately produce the lowest overall interest cost on the Bonds while the Interest Rate Mode for the Bonds is the Flexible Rate. Each Flexible Rate Period will be from one day to 270 days in length and will end on a day preceding a Business Day. If the Remarketing Agent fails to set the length of a Flexible Rate Period for any Bond, a new Flexible Rate Period lasting to, but not including, the next Business Day (or until the earlier Conversion or maturity of the Bonds) will be established automatically in accordance with the Indenture.

Semi-Annual Rate. If the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the interest rate on the Bonds for a particular Semi-Annual Rate Period will be the rate established by the Remarketing Agent no later than 2:00 p.m. (New York City time) on the Business Day immediately preceding the first day of such Semi-Annual Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof.

Annual Rate. If the Interest Rate Mode for the Bonds is the Annual Rate, the interest rate on the Bonds for a particular Annual Rate Period will be the rate of interest established by the Remarketing Agent no later than 12:00 noon (New York City time) on the Business Day preceding the first day of such Annual Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof.

Dutch Auction Rate. With respect to the 2006 Series B Bonds, if the Interest Rate Mode for the Bonds is the Auction Rate, the interest rate on the Bonds for a particular Auction Rate Period will be the rate established in accordance with the procedures set forth in the Indenture.

Long Term Rates and Long Term Rate Periods. If the Interest Rate Mode for the Bonds is the Long Term Rate, the interest rate on the Bonds for a particular Long Term Rate Period will be the rate established by the Remarketing Agent no later than 12:00 noon (New York City time) on the Business Day preceding the first day of such Long Term Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof. The Company will establish the duration of the Long Term Rate Period at the time that it directs the Conversion of the Interest Rate Mode to the Long Term Rate, and thereafter each successive Long Term Rate Period will be the same as the Long Term Rate Period so established by the Company until a different Long Term Rate Period is specified by the Company in accordance with the Indenture (in which case the duration of that Long Term Rate Period will control succeeding Long Term Rate Periods), subject in all cases to the occurrence of a Conversion Date or the maturity of the Bonds. Each Long Term Rate Period will be more than one year in duration, will be for a period which is an integral multiple of six months and will end on the day next preceding an Interest Payment Date; provided that if a Long Term Rate Period commences on a date other than a June 1 or December 1, such Long Term Rate Period may be for a period which is not an integral multiple of six months but will be of a duration as close as possible to (but not in excess of) such Long Term Rate Period established by the Company and will terminate on a day preceding an Interest Payment Date, and each successive Long Term Rate Period thereafter will be for the full period established by the Company until a different Long Term Rate Period is specified by the Company in accordance with the Indenture or until the occurrence of a Conversion Date or the maturity of the Bonds; provided further that no Long Term Rate Period will extend beyond the final maturity date of the Bonds.

Change of Long Term Rate Period. The Company may change from one Long Term Rate Period to another Long Term Rate Period on any Business Day on which the Bonds are subject to optional redemption as described under "— Redemptions — Optional Redemption" below upon notice from the Bond Registrar to the owners of Bonds as described below. With any notice of such change, the Company must also deliver an opinion of Bond Counsel stating that such change is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. Notwithstanding the foregoing, the Long Term Rate Period will not be changed to a new Long Term Rate Period if (A) the Remarketing Agent has not determined the interest rate for the new Long Term Rate Period in accordance with the terms of the Indenture or

(B) the Bond Registrar receives written notice from Bond Counsel prior to the effective date of the change to the effect that the opinion of such Bond Counsel required under the Indenture has been rescinded. Upon the occurrence of any of the events described in the preceding sentence, the Bonds will bear interest at the Weekly Rate commencing on the date which would have been the effective date of the proposed change of Long Term Rate Period, subject to the provisions described under "— Conversion of Interest Rate Modes — Cancellation of Conversion of Interest Rate Mode" below.

Notice to Owners of Change of Long Term Rate Period. The Bond Registrar will notify each registered owner of the change of Long Term Rate Period by first class mail at least 30 days in the case of a change in the Long Term Rate Period but not more than 45 days before each effective date of a change in the Long Term Rate Period. The notice will state those matters required to be set forth therein under the Indenture.

Failure to Determine Rate. If for any reason the interest rate for a Bond is not determined by the Remarketing Agent, except as described above under "— Change of Long Term Rate Period" and below under "— Conversion of Interest Rate Modes — Cancellation of Conversion of Interest Rate Mode," the interest rate for such Bond for the next succeeding interest rate period will be the interest rate in effect for such Bond for the preceding interest rate period and, pursuant to the terms of the Indenture, there will be no change in the then applicable Long Term Rate Period or any Conversion from the then applicable Interest Rate Mode. Notwithstanding the foregoing, if for any reason the interest rate for a Bond bearing interest at a Flexible Rate is not determined by the Remarketing Agent, the interest rate for such Bond for the next succeeding Interest Period will be equal to The Bond Market Association Municipal Swap Index™ (the "Municipal Index") as defined in the Indenture, and the Interest Period for such Bond will extend through the day preceding the next Business Day, until the Trustee is notified of a new Flexible Rate and Flexible Rate Period determined for such Bond by the Remarketing Agent.

Conversion of Interest Rate Modes

Method of Conversion. The Interest Rate Mode for the Bonds is subject to Conversion from time to time, in whole but not in part, on the dates specified below under "— Limitations on Conversion," at the option of the Company, upon notice from the Bond Registrar to the registered owners of the Bonds, as described below. With any notice of Conversion, the Company must also deliver to the Bond Registrar and the Credit Facility Issuer an opinion of Bond Counsel stating that such Conversion is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, other than a Conversion from the Daily Rate Period to the Weekly Rate Period or from the Weekly Rate Period to the Daily Rate Period.

Conditions Precedent to Conversions. The following conditions are applicable to Conversions of the Bonds:

(a) any Credit Facility to be held by the Trustee after the Conversion Date must be sufficient to cover the principal of and accrued interest on the outstanding Bonds for the maximum Interest Period permitted for that particular Interest Rate Mode plus 10 days at the maximum interest rate, and if a Credit Facility is to be held by the Trustee after the Conversion of the Bonds to a Long Term Rate Period, that Credit Facility must also extend for the entire Long Term Rate Period plus 10 days at the maximum interest rate; and

(b) if a Credit Facility is then in effect and the purchase price of the Bonds under the Indenture includes any premium, the Trustee will be entitled to draw on that Credit Facility in an aggregate amount sufficient to pay the applicable purchase price (including such premium) or, in the alternative, available moneys will be available in the necessary amount and are applied to the payment of such premium.

Limitations on Conversion. Any Conversion of the Interest Rate Mode for the Bonds must be in compliance with the following conditions: (i) the Conversion Date must be a date on which the Bonds are subject to optional redemption (see "— Redemptions — Optional Redemption" below); provided that any Conversion from the Daily Rate Period to a Weekly Rate Period or from the Weekly Rate Period to the Daily Rate Period must be on a Friday, with respect to the 2006 Series B Bonds, or Thursday, with respect to the 2008 Series A Bonds, and, with respect to the 2006 Series B Bonds, if the Conversion is to or from a Dutch Auction Rate Period, the Conversion Date must be the last Interest Payment Date in respect of that Dutch Auction Rate Period; (ii) if the proposed Conversion Date would not be an Interest Payment Date but for the Conversion, the Conversion Date must be a Business Day; (iii) if the Conversion is from the Flexible Rate, (a) the Conversion Date may be no earlier than the latest Interest Payment Date established prior to the giving of notice to the Remarketing Agent of such proposed Conversion and (b) no further Interest Payment Date may be established while the Interest Rate Mode is then the Flexible Rate if such Interest Payment Date would occur after the effective date of that Conversion; and (iv) after a determination is made requiring mandatory redemption of all Bonds pursuant to the Indenture (see "— Redemptions" below), no change in the Interest Rate Mode may be made prior to such mandatory redemption.

Notice to Owners of Conversion of Interest Rate Mode. The Bond Registrar will notify each registered owner of the Conversion by first class mail at least 15 days (30 days in the case of Conversion from or to the Semi-Annual Rate, the Annual Rate, a Long Term Rate or, with respect to the 2006 Series B Bonds, a Dutch Auction Rate) but not more than 45 days before the Conversion Date. The notice will state those matters required to be set forth therein under the Indenture.

Cancellation of Conversion of Interest Rate Mode. Notwithstanding the foregoing, no Conversion will occur if (i) the Remarketing Agent has not determined the initial interest rate for the new Interest Rate Mode in accordance with the terms of the Indenture, (ii) the Bonds that are to be purchased are not remarketed or sold by the Remarketing Agent or (iii) the Bond Registrar receives written notice from Bond Counsel prior to the opening of business on the effective date of Conversion to the effect that the opinion of such Bond Counsel required under the Indenture has been rescinded. If such Conversion fails to occur, such Bonds will automatically be converted to the Weekly Rate (with the first period adjusted in length so that the last day of such period will be a Wednesday) at the rate determined by the Remarketing Agent on the failed Conversion Date or, with respect to the 2006 Series B Bonds that bear interest at a Dutch Auction Rate, such Bonds will remain in such Interest Rate Mode; provided, that there must be delivered to the Issuer, the Trustee, the Bond Registrar, the Tender Agent, the Company, the Credit Facility Issuer and the Remarketing Agent an opinion of Bond Counsel to the effect that determining the interest rate to be borne by the Bonds at a Weekly Rate is authorized or permitted by the Act and is authorized under the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. If such opinion is not delivered on the failed Conversion Date, the Bonds will bear interest for a Rate Period of the same type and of substantially the same length as the Rate Period in effect prior to the failed Conversion Date at a rate of interest determined by the Remarketing Agent on the failed Conversion Date (or if shorter, the Rate Period ending on the day before the maturity date, with respect to the 2006 Series B Bonds); provided that if the Bonds then bear interest at the Long Term Rate, and if such opinion is not delivered on the date which would have been the effective date of a new Long Term Rate Period, the Bonds will bear interest at the Annual Rate, commencing on such date, at an Annual Rate determined by the Remarketing Agent on such date. If the proposed Conversion of Bonds fails as described herein, any mandatory purchase of such Bonds will remain effective.

Purchases of Bonds on Demand of Owner

If the Bonds are in the book-entry-only system, demands for purchase may be made by Beneficial Owners only through such Beneficial Owner's Direct Participant (as defined under the caption "— Book-Entry-Only System" below). If the Bonds are in certificated form, demands for purchase may be made only by registered owners. When the Interest Rate Mode is the Dutch Auction Rate, the Bonds are not subject to purchase on demand of the owners thereof.

Daily Rate. If the Interest Rate Mode for the Bonds is the Daily Rate, any Bond will be purchased on the demand of the registered owner thereof on any Business Day during a Daily Rate Period at a purchase price equal to the principal amount thereof plus accrued interest, if any, to the Purchase Date upon written notice or telephonic notice (to be immediately confirmed in writing) to the Tender Agent at its principal office not later than 10:00 a.m. (New York City time) on such Business Day.

Weekly Rate. If the Interest Rate Mode for the Bonds is the Weekly Rate, any Bond will be purchased on the demand of the registered owner thereof on any Business Day during a Weekly Rate Period at a purchase price equal to the principal amount thereof plus accrued interest, if any, to the Purchase Date upon written notice to the Tender Agent at its principal office at or before 5:00 p.m. (New York City time) on a Business Day not later than the seventh day prior to the Purchase Date.

Semi-Annual Rate. If the Interest Rate Mode for the Bonds is the Semi-Annual Rate, any Bond will be purchased on the demand of the registered owner thereof on any Interest Payment Date for a Semi-Annual Rate Period at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Annual Rate. If the Interest Rate Mode for the Bonds is the Annual Rate, any Bond will be purchased on the demand of the registered owner thereof on the final Interest Payment Date for such Annual Rate Period at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Long Term Rate. If the Interest Rate Mode for the Bonds is the Long Term Rate, any Bond will be purchased on the demand of the registered owner thereof on the final Interest Payment Date for such Long Term Rate Period (unless such date is the final maturity date) at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Limitations on Purchases on Demand of Owner. Notwithstanding the foregoing, there will be no purchase of (a) a portion of any Bond unless the portion to be purchased and the portion to be retained each will be in an authorized denomination or (b) any Bond upon the demand of the registered owner if an Event of Default under the Indenture with respect to the payment of principal of, interest on, or purchase price of, the Bonds has occurred and is continuing. Also, if the Interest Rate Mode for the Bonds is the Flexible Rate, the Bonds will not be subject to purchase on the demand of the registered owners thereof, but each Bond will be subject to mandatory purchase on each Conversion Date and on the Interest Payment Date with respect to such Bond, as described below under the caption "— Mandatory Purchases of Bonds."

Notice Required for Purchases. Any written notice delivered to the Tender Agent by an owner demanding the purchase of Bonds must (A) be delivered by the time and dates specified above, (B) state the number and principal amount (or portion thereof) of such Bond to be purchased, (C) state the Purchase Date on which such Bond is to be purchased, (D) irrevocably request such purchase and state that the owner agrees to deliver such Bond, duly endorsed in blank for transfer, with all signatures guaranteed, to the Tender Agent at or prior to 11:00 a.m. (1:00 p.m. if a tender during a Daily Rate Period and 12:00 noon if a tender during a Weekly Rate Period) (New York City time) on such Purchase Date.

Mandatory Purchases of Bonds

Mandatory Purchase on Conversion Dates or Change by the Company in Long Term Rate Period. The Bonds will be subject to mandatory purchase at a purchase price equal to the principal amount thereof, plus accrued interest, if any, to the Purchase Date, plus, if the Interest Rate Mode is the Long Term Rate, the redemption premium, if any, which would be payable as described under "— Redemptions — Optional Redemption" below, if the Bonds were redeemed (A) on the Purchase Date, (B) on each Conversion Date and (C) on the effective date of any change by the Company of the Long Term Rate Period. Such tender and purchase will be required even if the change in Long Term Rate Period or the Conversion is canceled pursuant to the Indenture.

Mandatory Purchase on Each Interest Payment Date for Flexible Rate Period. Whenever the Interest Rate Mode for the Bonds is the Flexible Rate, each Bond will be subject to mandatory purchase at a purchase price equal to the principal amount thereof, without premium, plus accrued interest, if any, to the Purchase Date, on each Interest Payment Date that interest on such Bond is payable at an interest rate determined for the Flexible Rate. Owners of Bonds will receive no notice of such mandatory purchase.

Mandatory Purchase on Day after End of the Semi-Annual Rate Period, the Annual Rate Period or the Long Term Rate Period. Whenever the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the Annual Rate or the Long Term Rate, such Bonds will be subject to mandatory purchase on the Business Day following the end of each Semi-Annual Rate Period, Annual Rate Period or Long Term Rate Period, as the case may be, for such Bond at a purchase price equal to the principal amount thereof plus accrued interest, if any, to such date.

Mandatory Purchase upon Delivery, Cancellation, Substitution, Extension, Termination or Expiration of Any Credit Facility or Replacement with an Alternate Credit Facility. If, at the option of the Company, a Credit Facility (other than the initial Letter of Credit) is delivered with respect to the Bonds subsequent to the Reoffering Date, the Bonds will be subject to mandatory tender for purchase at a purchase price equal to 100% of the principal amount thereof, plus accrued interest, if any, to the Purchase Date on the date of the delivery of the Credit Facility. In addition, if the Bonds are secured by a Credit Facility, the Bonds will be subject to mandatory tender for purchase at a purchase price equal to 100% of the principal amount thereof, plus accrued interest, if any, (A) on the Interest Payment Date at least five days prior to the date of the cancellation of or the expiration of the term of the then current Credit Facility and (B) on the Interest Payment Date on which a Credit Facility is replaced with an Alternate Credit Facility.

Notice to Owners of Mandatory Purchases. Notice to owners of a mandatory purchase of Bonds (except for mandatory purchase on each Interest Payment Date for Flexible Rate Periods) will be given by the Bond Registrar, by first class mail at least 15 days but not more than 45 days before the Purchase Date; provided, however, as an alternative to the foregoing, if DTC or its nominee is the registered owner of the Bonds, notice may be given to DTC not less than five days before the Purchase Date. The notice of mandatory purchase will state those matters required to be set forth therein under the Indenture. No notice of mandatory purchase will be given in connection with a mandatory purchase on an Interest Payment Date for a Flexible Rate Period.

Remarketing and Purchase of Bonds

The Indenture provides that, subject to the terms of a Remarketing Agreement with the Company, the Remarketing Agent will use its reasonable best efforts to offer for sale Bonds purchased upon demand of the owners thereof and, unless otherwise instructed by the Company and with the consent of any Credit Facility Issuer, upon mandatory purchase, provided that Bonds will not be remarketed upon the occurrence and continuance of certain Events of Default under the Indenture, except in the sole discretion of the Remarketing Agent. Each such sale will be at a price equal to the principal amount thereof, plus interest accrued to the date of sale. The Remarketing Agent, the Trustee, the Paying Agent, the Bond Registrar or the Tender Agent each may purchase any Bonds offered for sale for its own account.

On each date Bonds are to be purchased pursuant to optional or mandatory purchase under the Indenture, such Bonds will be purchased from the following sources in the order of priority indicated, provided that funds derived from clause (c) may not be combined with the funds derived from clauses (a) or (b) to purchase any Bonds:

(a) proceeds of the remarketing of such Bonds to persons other than the Company, its affiliates or the Issuer and furnished to the Tender Agent by the Remarketing Agent and deposited directly into, and held in, the Remarketing Proceeds Subaccount of the Purchase Fund established with the Tender Agent under the Indenture;

(b) proceeds of the Credit Facility, if any, furnished by the Trustee, as Tender Agent, and deposited by the Tender Agent directly into, and held in, the Credit Facility Subaccount of the Purchase Fund; and

(c) moneys paid by the Company (including the proceeds of the remarketing of the Bonds to the Company, its affiliates or the Issuer) to pay the purchase price to the Tender Agent.

If there is no Credit Facility in operation to secure the Bonds, any Bonds will be purchased with any moneys made available by the Company, including proceeds from the remarketing of the Bonds.

Payment of Purchase Price

When a book-entry-only system is not in effect, payment of the purchase price of any Bond will be payable (and delivery of a replacement Bond in exchange for the portion of any Bond not purchased if such Bond is purchased in part will be made) on the Purchase Date upon delivery of such Bond to the Tender Agent on such Purchase Date; provided that such Bond must be delivered to the Tender Agent: (i) at or prior to 12:00 noon (New York City time), in the case of Bonds delivered for purchase during a Weekly Rate Period or Flexible Rate Period, (ii) at or prior to 1:00 p.m. (New York City time), in the case of Bonds delivered for purchase during a Daily Rate Period or (iii) at or prior to 11:00 a.m. (New York City time), in the case of Bonds delivered for purchase during a Semi-Annual Rate Period, Annual Rate Period or Long Term Rate Period. If the date of such purchase is not a Business Day, the purchase price will be payable on the next succeeding Business Day.

Any Bond delivered for payment of the purchase price must be accompanied by an instrument of transfer thereof in form satisfactory to the Tender Agent executed in blank by the registered owner thereof and with all signatures guaranteed. The Tender Agent may refuse to accept delivery of any Bond for which an instrument of transfer satisfactory to it has not been provided and has no obligation to pay the purchase price of such Bond until a satisfactory instrument is delivered.

If the registered owner of any Bond (or portion thereof) that is subject to purchase pursuant to the Indenture fails to deliver such Bond with an appropriate instrument of transfer to the Tender Agent for purchase on the Purchase Date, and if the Tender Agent is in receipt of the purchase price therefor, such Bond (or portion thereof) nevertheless will be deemed purchased on the Purchase Date thereof. Any owner who so fails to deliver such Bond for purchase on (or before) the Purchase Date will have no further rights thereunder, except the right to receive the purchase price thereof from those moneys deposited with the Tender Agent in the Purchase Fund pursuant to the Indenture upon presentation and surrender of such Bond to the Tender Agent properly endorsed for transfer in blank with all signatures guaranteed.

When a book-entry-only system is in effect, the requirement for physical delivery of the Bonds will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on the records of DTC to the participant account of the Tender Agent.

Redemptions

Optional Redemption.

(i) Whenever the Interest Rate Mode for the Bonds is the Daily Rate or the Weekly Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof, plus interest accrued, if any, to the redemption date, on any Business Day.

(ii) Whenever the Interest Rate Mode for a Bond is the Flexible Rate, such Bond will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof, plus accrued interest, if any, to the redemption date with respect to the 2008 Series A Bonds, on any Interest Payment Date for that Bond.

(iii) Whenever the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof on any Interest Payment Date for each Semi-Annual Rate Period.

(iv) Whenever the Interest Rate Mode for the Bonds is the Annual Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof on the final Interest Payment Date for each Annual Rate Period.

(v) With respect to the 2006 Series B Bonds, whenever the Interest Rate Mode for the Bonds is the Dutch Auction Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, on the Business Day immediately succeeding any auction date at a redemption price of 100% of the principal amount thereof, together with accrued interest to the redemption date.

(vi) Whenever the Interest Rate Mode for the Bonds is the Long Term Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, (A) on the final Interest Payment Date for the then current Long Term Rate Period at a redemption price of 100% of the principal amount thereof and (B) prior to the end of the then current Long Term Rate Period at any time during the redemption periods and at the redemption prices set forth below, plus in each case interest accrued, if any, to the redemption date:

Original Length of Current Long Term Rate Period (Years)	**Commencement of Redemption Period**	**Redemption Price as Percentage of Principal**
2006 Series B Bonds:		
More than or equal to 11 years	First Interest Payment Date on or after the tenth anniversary of commencement of Long Term Rate Period	100%
Less than 11 years	Non-callable	Non-callable
2008 Series A Bonds:		
More than or equal to 10 years	First Interest Payment Date on or after the tenth anniversary of commencement of Long Term Rate Period	100%
Less than 10 years	Non-callable	Non-callable

Subject to certain conditions, including provision of an opinion of Bond Counsel that a change in the redemption provisions of the Bonds will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, the redemption periods and redemption prices may be revised, effective as of the Conversion Date, the date of a change in the Long Term Rate Period or a Purchase Date on the final Interest Payment Date during a Long Term Rate Period, to reflect Prevailing Market Conditions on such date as determined by the Remarketing Agent in its judgment. Any such revision of the redemption periods and redemption prices will not be considered an amendment or a supplement to the Indenture and will not require the consent of any Bondholder or any other person or entity.

Extraordinary Optional Redemption in Whole. The Bonds may be redeemed by the Issuer in whole at any time at 100% of the principal amount thereof plus accrued interest to the redemption date upon the exercise by the Company of an option under the Loan Agreement to prepay the loan if any of the following events occurs within 180 days preceding the giving of written notice by the Company to the Trustee of such election:

(i) if in the judgment of the Company, unreasonable burdens or excessive liabilities have been imposed upon the Company after the issuance of the Bonds with respect to the Project or the operation thereof, including without limitation federal, state or other ad valorem property, income or other taxes not imposed on the date of the Loan Agreement, other than ad valorem taxes levied upon privately owned property used for the same general purpose as the Project;

(ii) if the Project or a portion thereof or other property of the Company in connection with which the Project is used has been damaged or destroyed to such an extent so as, in the judgment of the Company, to render the Project or such other property of the Company in connection with which the Project is used unsatisfactory to the Company for its intended use, and such condition continues for a period of six months;

(iii) there has occurred condemnation of all or substantially all of the Project or the taking by eminent domain of such use or control of the Project or other property of the Company in connection with which the Project is used so as, in the judgment of the Company, to render the Project or such other property of the Company unsatisfactory to the Company for its intended use;

(iv) in the event changes, which the Company cannot reasonably control, in the economic availability of materials, supplies, labor, equipment or other properties or things necessary for the efficient operation of the generating station where the Project is located have occurred, which, in the judgment of the Company, render the continued operation of such generating station or any generating unit at such station uneconomical; or changes in circumstances after the issuance of the Bonds, including but not limited to changes in solid waste abatement, control and disposal requirements, have occurred such that the Company determines that use of the Project is no longer required or desirable;

(v) the Loan Agreement has become void or unenforceable or impossible of performance by reason of any changes in the Constitution of the Commonwealth of Kentucky or the Constitution of the United States of America or by reason of legislative or administrative action (whether state or federal) or any final decree, judgment or order of any court or administrative body, whether state or federal; or

(vi) a final order or decree of any court or administrative body after the issuance of the Bonds requires the Company to cease a substantial part of its operation at the generating station where the Project is located to such extent that the Company will be prevented from carrying on its normal operations at such generating station for a period of six months.

Extraordinary Optional Redemption in Whole or in Part. The Bonds are also subject to redemption in whole or in part at 100% of the principal amount thereof plus accrued interest to the redemption date at the option of the Company in an amount not to exceed the net proceeds received from insurance or any condemnation award received by the Issuer or the Company in the event of damage, destruction or condemnation of all or a portion of the Project, subject to receipt of an opinion of Bond Counsel that such redemption will not adversely affect the exclusion of interest on any of the Bonds from gross income for federal income tax purposes, and such net proceeds must be applied to reimburse the Credit Facility Issuer for drawings under the Credit Facility to redeem the Bonds. See "Summary of the Loan Agreement — Maintenance; Damage, Destruction and Condemnation." Such redemption may occur at any time, provided that if such event occurs while the Interest Rate Mode for the Bonds is the Flexible Rate or Semi-Annual Rate, such redemption must occur on a date on which the Bonds are otherwise subject to optional redemption as described above.

Mandatory Redemption; Determination of Taxability. The Bonds are required to be redeemed by the Issuer, in whole, or in such part as described below, at a redemption price equal to 100% of the principal amount thereof, without redemption premium, plus accrued interest, if any, to the redemption date, within 180 days following a "Determination of Taxability." As used herein, a "Determination of Taxability" means the receipt by the Trustee of written notice from a current or former registered owner of a Bond or from the Company or the Issuer of (i) the issuance of a published or private ruling or a technical advice memorandum by the Internal Revenue Service in which the Company participated or has been given the opportunity to participate, and which ruling or memorandum the Company, in its discretion, does not contest or from which no further right of administrative or judicial review or appeal exists, or (ii) a final determination from which no further right of appeal exists of any court of competent jurisdiction in the United States in a proceeding in which the Company has participated or has been a party, or has been given the opportunity to participate or be a party, in each case, to the effect that as a result of a failure by the Company to perform or observe any covenant or agreement or the inaccuracy of any representation contained in the Loan Agreement or any other agreement or certificate delivered in connection with the Bonds, the interest on the Bonds is included in the gross income of the owners thereof for federal income tax purposes, other than with respect to a person who is a "substantial user" or a "related person" of a substantial user of the Project within the meaning of the Section 147 of Internal Revenue Code of 1986, as amended (the "Code"); provided, however, that no such Determination of Taxability shall be considered to exist as a result of the Trustee receiving notice from a current or former registered owner of a Bond or from the Issuer unless (i) the Issuer or the registered owner or former registered owner of the Bond involved in such proceeding or action (A) gives the Company and the Trustee prompt notice of the commencement thereof, and (B) (if the Company agrees to pay all expenses in connection therewith) offers the Company the opportunity to control unconditionally the defense thereof, and (ii) either (A) the Company does not agree within 30 days of receipt of such offer to pay such expenses and liabilities and to control such defense, or (B) the Company shall exhaust or choose not to exhaust all available proceedings for the contest, review, appeal or rehearing of such decree, judgment or action which the Company determines to be appropriate. No Determination of Taxability described above will result from the inclusion of interest on any Bond in the computation of minimum or indirect taxes. All of the Bonds are required to be redeemed upon a Determination of Taxability as described above unless, in the opinion of Bond Counsel, redemption of a portion of such Bonds would have the result that interest payable on the remaining Bonds outstanding after the redemption would not be so included in any such gross income.

In the event any of the Issuer, the Company or the Trustee has been put on notice or becomes aware of the existence or pendency of any inquiry, audit or other proceedings relating to the Bonds being conducted by the Internal Revenue Service, the party so put on notice is required to give immediate written notice to the other parties of such matters. Promptly upon learning of the occurrence of a Determination of Taxability (whether or not the same is being contested), or any of the events described above, the Company is required to give notice thereof to the Trustee and the Issuer.

If the Internal Revenue Service or a court of competent jurisdiction determines that the interest paid or to be paid on any Bond (except to a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) is or was includable in the gross income of the recipient for federal income tax purposes for reasons other than as a result of a failure by the Company to perform or observe any of its covenants, agreements or representations in the Loan Agreement or any other agreement or certificate delivered in connection therewith, the Bonds are not subject to redemption. In such circumstances, Bondholders would continue to hold their Bonds, receiving principal and interest at the applicable rate as and when due, but would be required to include such interest payments in gross income for federal income tax purposes. Also, if the lien of the Indenture is discharged or defeased prior to the occurrence of a final Determination of Taxability, Bonds will not be redeemed as described herein.

General Redemption Terms. So long as a Credit Facility is in effect in respect of the Bonds, the redemption price (including accrued interest) will be paid from drawings under such Credit Facility or from moneys which otherwise constitute Available Moneys under the Indenture. Notice of redemption will be given by mailing a redemption notice conforming to the provisions and requirements of the Indenture by first class mail to the registered owners of the Bonds to be redeemed not less than 30 days (15 days if the Interest Rate Mode for the Bonds is the Flexible Rate, Daily Rate, Weekly Rate or, with respect to the 2006 Series B Bonds, the Dutch Auction Rate) but not more than 45 days prior to the redemption date.

Any notice mailed as provided in the Indenture will be conclusively presumed to have been given, irrespective of whether the owner receives the notice. Failure to give any such notice by mailing or any defect therein in respect of any Bond will not affect the validity of any proceedings for the redemption of any other Bond. No further interest will accrue on the principal of any Bond called for redemption after the redemption date if funds sufficient for such redemption have been deposited with the Paying Agent as of the redemption date. If the provisions for discharging the Indenture set forth below under the caption, "Summary of the Indenture — Discharge of Indenture" have not been complied with, any redemption notice will state that it is conditional on there being sufficient moneys to pay the full redemption price for the Bonds to be redeemed. So long as the Bonds are held in book-entry-only form, all redemption notices will be sent only to Cede & Co.

Book-Entry-Only System

Portions of the following information concerning DTC and DTC's book entry only system have been obtained from DTC. The Issuer, the Company and the Remarketing Agent make no representation as to the accuracy of such information.

Initially, DTC will act as securities depository for the Bonds and the Bonds initially will be issued solely in book-entry-only form to be held under DTC's book-entry-only system, registered in the name of Cede & Co. (DTC's partnership nominee). One fully registered bond in the aggregate principal amount of the Bonds will be deposited with DTC.

DTC, the world's largest depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934 (the "Exchange Act"). DTC holds and provides asset servicing for over 2.2 million issues of U.S. and non-U.S. equity, corporate and municipal debt issues, and money market instruments from over 100 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC, in turn, is owned by a number of Direct Participants of DTC and Members of the National Securities Clearing Corporation, Fixed Income Clearing Corporation, and Emerging Markets Clearing Corporation (NSCC, FICC and EMCC, also subsidiaries of DTCC), as well as by the New York Stock Exchange, Inc., the American Stock Exchange LLC and the National Association of Securities Dealers, Inc. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants" and, together with "Direct Participants," "Participants"). DTC has Standard & Poor's highest rating: AAA. The DTC Rules applicable to its Participants are on file with the SEC. More information about DTC can be found at www.dtcc.com and www.dtc.org.

Purchases of the Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser of each Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Bonds are to be accomplished by entries made on the books of Direct or Indirect Participants acting on behalf of Beneficial Owners.

Beneficial Owners will not receive certificates representing their ownership interests in the Bonds, except in the event that use of the book-entry system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of Bonds with DTC and their registration in the name of Cede & Co. or such other nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Redemption notices shall be sent to DTC. If less than all of the Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant to be redeemed.

Neither DTC nor Cede & Co. (nor such other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Issuer as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal and interest payments on the Bonds will be made to Cede & Co. or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts, upon DTC's receipt of funds and corresponding detail information from the Issuer or the Trustee on the payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC nor its nominee, the Trustee, the Company or the Issuer, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Issuer or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

A Beneficial Owner shall give notice to elect to have its Bonds purchased or tendered, through its Participant, to the Tender Agent, and shall effect delivery of such Bonds by causing the Direct Participant to transfer the Participant's interest in the Bonds, on DTC's records, to the Tender Agent. The requirement for physical delivery of Bonds in connection with a demand for purchase or a mandatory purchase will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on DTC's records and followed by a book-entry credit of tendered Bonds to the Tender Agent's DTC account.

DTC may discontinue providing its services as securities depository with respect to the Bonds at any time by giving reasonable notice to the Issuer, the Company, the Tender Agent and the Trustee, or the Issuer, at the request of the Company, may remove DTC as the securities depository for the Bonds. Under such circumstances, in the event that a successor securities depository is not obtained, bond certificates are required to be delivered as described in the Indenture (see "— Revision of Book Entry Only System; Replacement Bonds" below). The Beneficial Owner, upon registration of certificates held in the Beneficial Owner's name, will become the registered owner of the Bonds.

So long as Cede & Co. is the registered owner of the Bonds, as nominee of DTC, references herein to the registered owners of the Bonds will mean Cede & Co. and will not mean the Beneficial Owners. Under the Indenture, payments made by the Trustee to DTC or its nominee will satisfy the Issuer's obligations under the Indenture, the Company's obligations under the Loan Agreement, to the extent of the payments so made. Beneficial Owners will not be, and will not be considered by the Issuer or the Trustee to be, and will not have any rights as, owners of Bonds under the Indenture.

The Trustee and the Issuer, so long as a book entry only system is used for the Bonds, will send any notice of redemption or of proposed document amendments requiring consent of registered owners and any other notices required by the document (including notices of Conversion and mandatory purchase) to be sent to registered owners only to DTC (or any successor securities depository) or its nominee. Any failure of DTC to advise any Direct Participant, or of any Direct Participant or Indirect Participant to notify the Beneficial Owner, of any such notice and its content or effect will not affect the validity of the redemption of the Bonds called for redemption, the document amendment, the Conversion, the mandatory purchase or any other action premised on that notice.

The Issuer, the Company, the Trustee and the Remarketing Agent cannot and do not give any assurances that DTC will distribute payments on the Bonds made to DTC or its nominee as the registered owner or any redemption or other notices, to the Participants, or that the Participants or others will distribute such payments or notices to the Beneficial Owners, or that they will do so on a timely basis, or that DTC will serve and act in the manner described in this Reoffering Circular.

THE ISSUER, THE COMPANY, THE REMARKETING AGENT AND THE TRUSTEE WILL HAVE NO RESPONSIBILITY OR OBLIGATION TO ANY DIRECT PARTICIPANT, INDIRECT PARTICIPANT OR ANY BENEFICIAL OWNER OR ANY OTHER PERSON NOT SHOWN ON THE REGISTRATION BOOKS OF THE TRUSTEE AS BEING A REGISTERED OWNER WITH RESPECT TO: (1) THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC OR ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT; (2) THE PAYMENT OF ANY AMOUNT DUE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER IN RESPECT OF THE PRINCIPAL AMOUNT OR REDEMPTION OR PURCHASE PRICE OF OR INTEREST ON THE BONDS; (3) THE DELIVERY OF ANY NOTICE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER WHICH IS REQUIRED OR PERMITTED TO BE GIVEN TO REGISTERED OWNERS UNDER THE TERMS OF THE INDENTURE; (4) THE SELECTION OF THE BENEFICIAL OWNERS TO RECEIVE PAYMENT IN THE EVENT OF ANY PARTIAL REDEMPTION OF THE BONDS; OR (5) ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC AS REGISTERED OWNER.

Revision of Book-Entry-Only System; Replacement Bonds. In the event that DTC determines not to continue as securities depository or is removed by the Issuer, at the direction of the Company, as securities depository, the Issuer, at the direction of the Company, may appoint a successor securities depository reasonably acceptable to the Trustee. If the Issuer does not or is unable to appoint a successor securities depository, the Issuer will issue and the Trustee will authenticate and deliver fully registered Bonds, in authorized denominations, to the assignees of DTC or their nominees.

In the event that the book-entry-only system is discontinued, the following provisions will apply. The Bonds may be issued in denominations of $5,000 and multiples thereof, if the Interest Rate Mode is the Semi-Annual Rate, the Annual Rate or the Long Term Rate; in denominations of $100,000 and multiples of $5,000 in excess thereof, if the Interest Rate Mode is the Flexible Rate; in denominations of $100,000 and multiples thereof, if the Interest Rate Mode is the Daily Rate or the Weekly Rate; and with respect to 2006 Series B Bonds, in denominations of $25,000 and multiples thereof; provided, that, (i) if the Bonds bear interest at the Daily Rate or the Weekly Rate, one Bond may be in the denomination of, or include an additional, $47,405 and (ii) if the Bonds bear interest at the Semi-Annual Rate, the Annual Rate, the Long Term Rate or the Flexible Rate, one Bond may be in the denomination of, or include an additional $2,405. Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the principal office of the Bond Registrar, accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond during the fifteen days before any mailing of a notice of redemption, after such Bond has been called for redemption in whole or in part, or after such Bond has been tendered or deemed tendered for optional or mandatory purchase as described under "Purchases of Bonds on Demand of Owner" and "Mandatory Purchases of Bonds." Registration of transfers and exchanges will be made without charge to the owners of Bonds, except that the Bond Registrar may require any owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

Security; Limitation on Liens

Payment of the principal of and interest and any premium on the Bonds are secured by an assignment by the Issuer to the Trustee of the Issuer's interest in and to the Loan Agreement and all payments to be made pursuant thereto (other than certain indemnification and expense payments and notification rights). Pursuant to the Loan Agreement, the Company has agreed to pay, among other things, amounts sufficient to pay the aggregate principal amount of and premium, if any, on the Bonds, together with interest thereon as and when the same become due. The Company further will agree to make payments of the purchase price of the Bonds tendered for purchase to the extent that funds are not otherwise available therefor under the provisions of the Indenture.

The Bonds are unsecured general obligations of the Company, ranking on a parity with the Company's obligations under the Loan Agreement to make payments on the Bonds..

In the Loan Agreement, the Company has covenanted that it will not issue, assume or guarantee any debt for borrowed money secured by any mortgage, security interest, pledge, or lien ("mortgage") on any of the Company's operating property (as defined below), whether the Company owns it at the date hereof or acquires it later, and will not permit to exist any debt for borrowed money secured by a mortgage on any such property unless the Company similarly secures its obligations under the Loan Agreement to make payments to the Trustee in sufficient amounts to pay the principal of, premium, if any, and interest required to be paid on the Bonds. This restriction will not apply to:

- mortgages on any property existing at the time the Company acquires the property or at the time the Company acquires the corporation owning the property;
- purchase money mortgages;
- specified governmental mortgages; or
- any extension, renewal or replacement (or successive extensions, renewals or replacements) of any mortgage referred to in the three clauses listed above, so long as the principal amount of indebtedness secured under this clause and not otherwise authorized by the clauses listed above does not exceed the principal amount of indebtedness secured at the time of the extension, renewal or replacement.

In addition, the Company can also issue secured debt so long as the amount of the secured debt does not exceed the greater of 10% of net tangible assets or 10% of capitalization.

The Company will not, so long as any of the Bonds are outstanding, issue, assume, guarantee or permit to exist any debt of the Company secured by a mortgage, the creditor of which controls, is controlled by or is under common control with, the Company.

For purposes of this limitation on liens, “operating property” means (i) any interest in real property owned by the Company and (ii) any asset owned by the Company that is depreciable in accordance with generally accepted accounting principles.

The Letter of Credit

The following summarizes certain provisions of the Letter of Credit and the Reimbursement Agreement, to which reference is made for the detailed provisions thereof. Unless otherwise defined in this Reoffering Circular, capitalized terms in the following summary are used as defined in the Letter of Credit and the Reimbursement Agreement. The Company is permitted under the Indenture to deliver an Alternate Credit Facility to replace the related Letter of Credit. Any such Alternate Credit Facility must meet certain requirements described in the Indenture.

The Letter of Credit

The Letter of Credit will be an irrevocable transferable direct pay letter of credit issued by the Bank in order to provide additional security for the payment of principal of, purchase price of, interest on and premium, if applicable, on any date when payments under the Bonds are due, including principal and interest payments and payments upon tender, redemption, acceleration or maturity of the Bonds. The Letter of Credit will provide for direct payments to or upon the order of the Trustee as set forth in the Letter of Credit in amounts sufficient to pay to or upon the order of the Trustee, upon request and in accordance with the terms thereof.

The Letter of Credit will be issued in an amount equal to the aggregate principal amount of the outstanding Bonds, plus an amount that represents interest accrued thereon at an assumed rate of 15% per annum for 45 days (the “Credit Amount”). The Trustee, upon compliance with the terms of the Letter of Credit, is authorized to draw up to (a) an amount sufficient (i) to pay principal of the Bonds, when due, whether at maturity or upon redemption or acceleration, and (ii) to pay the portion of the purchase price of the Bonds delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed (a “Liquidity Drawing”) equal to the principal amount of the Bonds, plus (b) an amount not to exceed 45 days of accrued interest on such Bonds at an assumed rate of 15% per annum (i) to pay interest on the Bonds, when due, and (ii) to pay the portion of the purchase price of the Bonds, delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed, equal to the interest accrued, if any, on the Bonds.

The amount available under the Letter of Credit will be automatically reduced by the amount of any drawing thereunder, subject to reinstatement as described below. With respect to a drawing by the Trustee solely to pay interest on the Bonds on an Interest Payment Date, the amount available under the Letter of Credit will be automatically reinstated in the amount of such drawing effective on the earlier of (i) receipt by the Bank from the Company of reimbursement of any drawing solely to pay interest in full or (ii) at the opening of business on the eleventh calendar day after the date the Bank honors such drawing, unless the Trustee has received written notice from the Bank by the tenth calendar day after the date the Bank honors such drawing the Bank is not so reinstating the available amount due to the Company’s failure to reimburse the Bank for such drawing in full, or that an event of default has occurred and is continuing under the Reimbursement Agreement and, in either case, directing, an acceleration of the Bonds pursuant to the Indenture. With respect to a Liquidity Drawing under the Letter of Credit, the amount available under the Letter of Credit will be automatically reduced by the principal amount of the Bonds purchased with the proceeds of such drawing plus the amount of accrued interest on such Bonds. In the event of the remarketing of the Bonds purchased with the proceeds of a Liquidity Drawing, the amount available under the Letter of Credit will be automatically reinstated upon receipt by the Bank or the Trustee on the Bank's behalf of an amount equal to such principal amount plus accrued interest.

The Letter of Credit will terminate on the earliest to occur of:

(a) the Bank's close of business on December 18, 2009 (such date, as extended from time to time in accordance with the Letter of Credit is defined as the "Stated Expiration Date");

(b) the Bank's close of business on the date which is five Business Days following the date of receipt by the Bank of a certificate from the Trustee certifying that (a) no Bonds remain Outstanding within the meaning of the Indenture, (b) all drawings required to be made under the Indenture and available under the Letter of Credit have been made and honored, (c) an Alternate Credit Facility has been delivered to the Trustee in accordance with the Indenture to replace the Letter of Credit or (d) all of the outstanding Bonds were converted to Bonds bearing interest at a rate other than the Daily Rate or the Weekly Rate;

(c) the Bank's close of business on the date of receipt by the Bank of a certificate from the Trustee confirming that the Trustee is required to terminate the Letter of Credit in accordance with the terms of the Indenture; or

(d) the date on which the Bank receives and honors an acceleration drawing certificate.

The Reimbursement Agreement

Pursuant to the Reimbursement Agreement, the Company is obligated to reimburse the Bank for all amounts drawn under the Letter of Credit, and to pay interest on all such amounts. The Company has also agreed to pay the Bank a periodic fee for issuing and maintaining the Letter of Credit.

The Reimbursement Agreement imposes various covenants and agreements, including various financial and operating covenants, on the Company. Such covenants include, but are not limited to, covenants relating to (i) inspection of the books and financial records of the Company; (ii) creation of liens; (iii) liquidations, mergers, consolidations or sales of all or substantially all of the Company's assets; and (iv) disposition of assets. Any such covenants may be amended, waived or modified at any time by the Bank and without the consent of the Trustee or the holders of the Bonds. Under certain circumstances, the failure of the Company to comply with such covenants may result in a mandatory tender or acceleration of the Bonds.

The following events will constitute an "event of default" under the Reimbursement Agreement:

(a) nonpayment of certain fees and other amounts required to be paid or reimbursed by the Company under the Reimbursement Agreement to the Bank within five days after the same was required to be paid;

(b) any representation or warranty made or deemed made by or on behalf of the Company or any of its Significant Subsidiaries to the Bank under or in connection with the Reimbursement Agreement or any other Transaction Document, any advance or any certificate or information delivered pursuant to or in connection with the Reimbursement Agreement or any other Transaction Document, was false or misleading in any material respect as of the time it was made or furnished;

(c) an "event of default" (not due to the Bank's failure to properly honor a drawing on the Letter of Credit) occurred under the Indenture or any of the other Transaction Documents and any applicable grace period has expired;

(d) the breach by the Company or any of its Significant Subsidiaries of any of the terms or provisions of certain covenants contained in the Reimbursement Agreement including, but not limited to, covenants relating to the provision of notice to the Bank regarding an "event of default" or "default" under the Reimbursement Agreement, the corporate existence and license or qualification and good standing of the Company in jurisdictions in which it owns or leases property, the creation of liens, the liquidation, merger, consolidation or sale of all or substantially all of the assets of the Company and the disposition of assets;

(e) the breach by the Company or any of its Significant Subsidiaries (other than a breach which constitutes a "default" described above) of any of the terms or provisions of the Reimbursement Agreement or any Security Document that is not remedied within thirty (30) days after an executive officer of the Company has actual knowledge of such default or written notice of such default has been given to the Company by the Bank;

(f) the Bonds cease to be valid for any reason;

(g) a default or event of default has occurred at any time under the terms of any other agreement involving borrowed money or the extension of credit or any other Indebtedness under which the Company or any of its Significant Subsidiaries may be obligated for the payment of $50,000,000 or more in the aggregate, and such breach, default or event of default continues beyond any period of grace permitted with respect thereto and as a result thereof such Indebtedness is accelerated, becomes due or is otherwise required to be repurchased or redeemed prior to the scheduled date of maturity thereof;

(h) a proceeding has been instituted in a court having jurisdiction in the premises seeking a decree or order for relief in respect of the Company or any Significant Subsidiary in an involuntary case under any applicable bankruptcy, insolvency, reorganization or other similar law now or hereafter in effect, or for the appointment of a receiver, liquidator, assignee, custodian, trustee, sequestrator, conservator (or similar official) of the Company or any Significant Subsidiary for any substantial part of its property, or for the winding-up or liquidation of its affairs, and such proceeding shall remain undismissed or unstayed and in effect for a period of sixty (60) consecutive days; such court shall enter a decree or order granting any of the relief sought in such proceeding; or the Company or any Significant Subsidiary shall consent, approve or otherwise acquiesce in any of the actions sought in such proceeding;

(i) the Company or any Significant Subsidiary shall commence a voluntary case under any applicable bankruptcy, insolvency, reorganization or other similar law now or hereafter in effect, shall consent to the entry of an order for relief in an involuntary case under any such law, or shall consent to the appointment or taking possession by a receiver, liquidator, assignee, custodian, trustee, sequestrator, conservator (or other similar official) of itself or for any substantial part of its property or shall make a general assignment for the benefit of creditors, or shall fail generally to pay its debts as they become due, or shall take any action in furtherance of any of the foregoing;

(j) without the application, approval or consent of the Company or any of its Significant Subsidiaries, a receiver, trustee, examiner, liquidator or similar official shall be appointed for the Company or any of its Significant Subsidiaries, or for any substantial portion of its Property, or a proceeding described in paragraph (h) above has been instituted against the Company or any of its Significant Subsidiaries, and such appointment continues undischarged or such proceeding continues undismissed or unstayed for a period of 60 consecutive days;

(k) any of the following occurs: (i) any Reportable Event which constitutes grounds under Section 4042 of ERISA for the termination of any Plan by the PBGC or the appointment of a trustee to administer or liquidate any Plan, shall have occurred and be continuing; (ii) a notice of intent to terminate any Plan shall have been filed with the PBGC under Section 4041 of ERISA; (iii) the PBGC shall give notice under Section 4042 of ERISA of its intent to institute proceedings to terminate any Plan or Plans or to appoint a trustee to administer or liquidate any Plan; (iv) the Company or any member of the ERISA Group shall fail to make any contributions when due to a Plan or a Multiemployer Plan; (v) the Company or any member of the ERISA Group shall make any amendment to a Plan with respect to which security is required under Section 307 of ERISA; (vi) the Company or any member of the ERISA Group shall withdraw completely or partially from a Multiemployer Plan pursuant to Subtitle E of Title IV of ERISA; or (vii) the Company or any member of the ERISA Group shall withdraw within the meaning of Section 4063 of ERISA (or shall be deemed under Section 4062(e) of ERISA to withdraw) from a Multiple Employer Plan; and, with respect to any of such events specified in clause (i), (ii), (iii), (iv), (v), (vi) or (vii), such occurrence would be reasonably likely to result in a Material Adverse Effect;

(l) any final judgment(s) or order(s) for the payment of money shall be entered against the Company or any of its Significant Subsidiaries by a court having jurisdiction in the premises which judgment is not discharged, vacated, bonded or stayed pending appeal within a period of thirty (30) days from the date of entry if the aggregate uninsured amount of all such judgments and orders exceeds $50,000,000;

(m) the Company or any of its Significant Subsidiaries ceases to conduct business (other than as permitted hereunder) or the Company is enjoined, restrained or in any way prevented by court order from conducting all or any material part of its business and such injunction, restraint or other preventive order is not dismissed within thirty (30) days after the entry thereof; or

(n) E.ON AG fails to own, directly or indirectly, at least seventy-five percent (75%) of the outstanding Voting Capital of the Company.

For purposes of the foregoing:

"Bond Documents" means the Indenture, the Custody Agreement, the Loan Agreement, the Bonds and the Remarketing Agreement.

"Material Adverse Effect" means (i) a material adverse change in the business, property, condition (financial or otherwise), operations or results of operations of the Company and its subsidiaries taken as a whole, (ii) a material adverse change in the ability of the Company to perform its obligation under the Transaction Documents or (iii) a material adverse change in the validity or enforceability of any of the Transaction Documents or the rights or remedies of the Bank thereunder.

"Security Documents" means the Custody, Pledge and Security Agreement dated as of December 19, 2008 among the Trustee, the Company and the Bank with respect to any Bond purchased during the period from and including the date of its purchase with proceeds of a Liquidity Drawing to but excluding the date on which such Bond is purchased by any person as a result of a remarketing of such Bond pursuant to the Remarketing Agreement and the Indenture.

"Transaction Documents" means, collectively, the Reimbursement Agreement, Bond Documents, the Security Documents and all other operative documents relating to the issuance, sale and securing of the Bonds (including without limitation any document(s) or instrument(s) through which the Bonds are now or hereafter collateralized, such as mortgages, security agreements, etc.).

Summary of the Loan Agreement

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the Loan Agreement. This description is only a summary and does not purport to be complete and definitive. Reference is made to the Loan Agreement for the detailed provisions thereof.

General

The Loan Agreement initially commenced as of its initial date, and, with respect to the 2006 Series A Bonds, is amended and restated as of September 1, 2008, and will end on the earliest to occur of October 1, 2034, with respect to the 2006 Series B Bonds, or February 1, 2032, with respect to the 2008 Series A Bonds, or the date on which all of the Bonds have been fully paid or provision has been made for such payment pursuant to the Indenture. See "Summary of the Indenture — Discharge of Indenture."

The Company has agreed to repay the loan pursuant to the Loan Agreement by making timely payments to the Trustee in sufficient amounts to pay the principal of, premium, if any, and interest required to be paid on the Bonds on each date upon which any such payments are due. The Company has also agreed to pay (a) the agreed upon fees and expenses of the Trustee, the Bond Registrar, the Tender Agent and the Paying Agent and all other amounts which may be payable to the Trustee, the Bond Registrar, the Paying Agent, the Auction Agent with respect to the 2006 Series B Bonds, and the Tender Agent, as may be applicable, under the Indenture, (b) the expenses in connection with any redemption of the Bonds and (c) the reasonable expenses of the Issuer.

The Company covenants and agrees with the Issuer that it will cause the purchase of tendered Bonds that are not remarketed in accordance with the Indenture and, to that end, the Company will cause funds to be made available to the Tender Agent at the times and in the manner required to effect such purchases in accordance with the Indenture; provided, however, that the obligation of the Company to make any such payment will be reduced by the amount of (A) moneys paid by the Remarketing Agent as proceeds of the remarketing of such Bonds; (B) moneys drawn under a Credit Facility, if any, for the purpose of paying such purchase price and (C) other moneys made available by the Company (see "Summary of the Bonds — Remarketing and Purchase of Bonds").

All payments to be made by the Company to the Issuer pursuant to the Loan Agreement (except the fees and reasonable out-of-pocket expenses of the Issuer, the Trustee, the Paying Agent, the Bond Registrar, the Auction Agent with respect to the 2006 Series B Bonds and the Tender Agent, and amounts related to indemnification) have been assigned by the Issuer to the Trustee, and the Company will pay such amounts directly to the Trustee. The obligations of the Company to make the payments pursuant to the Loan Agreement are absolute and unconditional.

Maintenance of Tax Exemption

The Company and the Issuer have agreed not to take any action that would result in the interest paid on the Bonds being included in gross income of any Bondholder (other than a holder who is a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) for federal income tax purposes or that adversely affects the validity of the Bonds.

Limitation on Liens

The Company has agreed that, so long as any of the Bonds are outstanding, it will not create, assume or guarantee debt for borrowed money secured by any mortgage, except as described above under "Security; Limitation on Liens."

Payment of Taxes

The Company has agreed to pay certain taxes and other governmental charges that may be lawfully assessed, levied or charged against or with respect to the Project (see, however, subparagraph (i) under "Summary of the Bonds — Redemptions — Extraordinary Optional Redemption in Whole"). The Company may contest such taxes or other governmental charges unless the security provided by the Indenture would be materially endangered.

Maintenance; Damage, Destruction and Condemnation

So long as any Bonds are outstanding, the Company will maintain the Project or cause the Project to be maintained in good working condition and will make or cause to be made all proper repairs, replacements and renewals necessary to continue to constitute the Project as solid waste disposal facilities under Section 142(a)(6) of the Code and the Act. However, the Company will have no obligation to maintain, repair, replace or renew any portion of the Project, the maintenance, repair, replacement or renewal of which becomes uneconomical to the Company because of certain events, including damage or destruction by a cause not within the Company's control, condemnation of the Project, change in government standards and regulations, economic or other obsolescence or termination of operation of generating facilities to the Project.

The Company, at its own expense, may remodel the Project or make substitutions, modifications and improvements to the Project as it deems desirable, which remodeling, substitutions, modifications and improvements will be deemed, under the terms of the Loan Agreement to be a part of the Project. The Company may not, however, change or alter the basic nature of the Project or cause it to lose its status under Section 142(a)(6) of the Code and the Act.

If, prior to the payment of all Bonds outstanding, the Project or any portion thereof is destroyed, damaged or taken by the exercise of the power of eminent domain and the Issuer or the Company receives net proceeds from insurance or a condemnation award in connection therewith, the Company must (i) cause such net proceeds to be used to repair or restore the Project or (ii) reimburse the Credit Facility Issuer for drawings under the Credit Facility for the redemption of the Bonds in whole or in part at their principal amount, which, by the opinion of Bond Counsel, will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes. See “Summary of the Bonds — Redemptions — Extraordinary Optional Redemption in Whole or in Part.”

Project Insurance

The Company will insure the Project in a manner consistent with general industry practice.

Assignment, Merger and Release of Obligations of the Company

The Company may assign the Loan Agreement, pursuant to an opinion of Bond Counsel that such assignment will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, without obtaining the consent of either the Issuer or the Trustee. Such assignment, however, will not relieve the Company from primary liability for any of its obligations under the Loan Agreement and performance and observance of the other covenants and agreements to be performed by the Company. The Company may dispose of all or substantially all of its assets or consolidate with or merge into another corporation, provided the acquirer of the Company’s assets or the corporation with which it will consolidate with or merge into is a corporation or other business organization organized and existing under the laws of the United States of America or one of the states of the United States of America or the District of Columbia, is qualified and admitted to do business in the Commonwealth of Kentucky, assumes in writing all of the obligations and covenants of the Company under the Loan Agreement and delivers a copy of such assumption to the Issuer and Trustee.

Release and Indemnification Covenant

The Company will indemnify and hold the Issuer harmless against any expense or liability incurred, including attorneys’ fees, resulting from any loss or damage to property or any injury to or death of any person occurring on or about or resulting from any defect in the Project or from any action commenced in connection with the financing thereof.

Events of Default

Each of the following events constitutes an “Event of Default” under the Loan Agreement:

(1) failure by the Company to pay the amounts required for payment of the principal of, including purchase price for tendered Bonds and redemption and acceleration prices, and interest accrued, on the Bonds, at the times specified therein taking into account any periods of grace provided in the Indenture and the Bonds for the applicable payment of interest on the Bonds (see “Summary of the Indenture — Defaults and Remedies”);

(2) failure by the Company to observe and perform any covenant, condition or agreement, other than as referred to in paragraph (1) above, for a period of thirty days after written notice by the Issuer or Trustee, provided, however, that if such failure is capable of being corrected, but cannot be corrected in such 30-day period, it will not

constitute an Event of Default under the Loan Agreement if corrective action with respect thereto is instituted within such period and is being diligently pursued;

(3) certain events of bankruptcy, dissolution, liquidation, reorganization or insolvency of the Company; or

(4) the occurrence of an Event of Default under the Indenture.

Under the Loan Agreement, certain of the Company's obligations (other than the Company's obligations, among others, (i) not to permit any action which would result in interest paid on the Bonds being included in gross income for federal and Kentucky income taxes; (ii) to maintain its corporate existence and good standing, and to neither dispose of all or substantially all of its assets or consolidate with or merge into another corporation unless certain provisions of the Loan Agreement are satisfied; and (iii) to make loan payments and certain other payments under the provisions of the Loan Agreement) may be suspended if by reason of force majeure (as defined in the Loan Agreement) the Company is unable to carry out such obligations.

Remedies

Upon the happening of an Event of Default under the Loan Agreement, the Trustee, on behalf of the Issuer, may, among other things, take whatever action at law or in equity may appear necessary or desirable to collect the amounts then due and thereafter to become due, or to enforce performance and observance of any obligation, agreement or covenant of the Company, under the Loan Agreement.

Any amounts collected upon the happening of any such Event of Default must be applied in accordance with the Indenture or, if the Bonds have been fully paid (or provision for payment thereof has been made in accordance with the Indenture) and all other liabilities of the Company accrued under the Indenture and the Loan Agreement have been paid or satisfied, made available to the Company.

Options to Prepay, Obligation to Prepay

The Company may prepay the loan pursuant to the Loan Agreement, in whole or in part, on certain dates, at the prepayment prices as shown under the captions "Summary of the Bonds — Redemptions — Optional Redemption," "— Extraordinary Optional Redemption in Whole" and "— Extraordinary Optional Redemption in Whole or in Part." Upon the occurrence of the event described under the caption "Summary of the Bonds — Redemptions — Mandatory Redemption; Determination of Taxability," the Company will be obligated to prepay the loan in an aggregate amount sufficient to redeem the required principal amount of the Bonds.

In each instance, the loan prepayment price must be a sum sufficient, together with other funds deposited with the Trustee and available for such purpose, to redeem the requisite amount of the Bonds at a price equal to the applicable redemption price plus accrued interest to the redemption date, and to pay all reasonable and necessary fees and expenses of the Trustee, the Paying Agent and, with respect to the 2008 Series A Bonds, the Bond Registrar and the Tender Agent and all other liabilities of the Company under the Loan Agreement accrued to the redemption date.

Amendments and Modifications

No amendment or modification of the Loan Agreement is permissible without the written consent of the Trustee. The Issuer and the Trustee may, however, without the consent of or notice to any Bondholders, enter into any amendment or modification of the Loan Agreement (i) which may be required by the provisions of the Loan Agreement or the Indenture, (ii) for the purpose of curing any ambiguity or formal defect or omission, (iii) in connection with any modification or change necessary to conform the Loan Agreement with changes and modifications in the Indenture or (iv) in connection with any other change which, in the judgment of the Trustee, does not adversely affect the Trustee or the Bondholders. Except for such amendments, the Loan Agreement may be amended or modified only with the consent of the Bondholders holding a majority in principal amount of the Bonds then outstanding (see "Summary of the Indenture — Supplemental Indentures" for an explanation of the procedures necessary for Bondholder consent); provided, however, that the approval of the Bondholders holding 100% in principal amount of the Bonds then outstanding is necessary to effectuate an amendment or modification with respect to the Loan Agreement of the type described in clauses (i) through (iv) of the first sentence of the second paragraph of "Summary of the Indenture — Supplemental Indentures." Any amendments, changes or modification of the Loan Agreement that require the consent of the Bondholders must additionally be approved by the Credit Facility Issuer, if the Bonds are at the time secured by a Credit Facility. Additionally, so long as a Credit Facility is in place or while any amounts are outstanding under a Reimbursement Agreement, the Credit Facility Issuer must consent in writing to any amendment, change, or modification to the Agreement.

Summary of the Indenture

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the Indenture. This description is only a summary and does not purport to be complete and definitive. Reference is made to the Indenture for the detailed provisions thereof.

Security

Pursuant to the Indenture, the Issuer has assigned and pledged to the Trustee its interest in and to the Loan Agreement, including payments and other amounts due the Issuer thereunder, together with all moneys, property and securities from time to time held by the Trustee under the Indenture (with certain exceptions, including moneys held in or earnings on the Rebate Fund and the Purchase Fund). The Bonds are not directly secured by the Project.

No Pecuniary Liability of the Issuer

No provision, covenant or agreement contained in the Indenture or in the Loan Agreement, nor any breach thereof, will constitute or give rise to any pecuniary liability of the Issuer or any charge upon any of its assets or its general credit or taxing powers. The Issuer has not obligated itself by making the covenants, agreements or provisions contained in the Indenture or in the Loan Agreement, except with respect to the Project and the application of the amounts assigned to payment of the principal of, premium, if any, and interest on the Bonds.

The Bond Fund

The payments to be made by the Company pursuant to the Loan Agreement to the Issuer and certain other amounts specified in the Indenture will be deposited into a Bond Fund established pursuant to the Indenture (the "Bond Fund") and will be maintained in trust by the Trustee. Moneys in the Bond Fund will be used for the payment of the principal of, premium, if any, and interest on the Bonds, and for the redemption of Bonds prior to maturity in the following order of priority: (i) proceeds of the Credit Facility, if any, deposited into the Bond Fund in accordance with the Indenture and (ii) any other moneys provided by or on behalf of the Company. Any moneys held in the Bond Fund will be invested by the Trustee at the specific written direction of the Company in certain Governmental Obligations, investment-grade corporate obligations and other investments permitted under the Indenture.

So long as a Credit Facility is in held by the Trustee and there is no default in the payment of principal or redemption price of or interest on the Bonds, any amounts in the Bond Fund provided by or on behalf of the Company will be paid to the Credit Facility Issuer to the extent of any amounts that the Company owes the Credit Facility Issuer pursuant to the Reimbursement Agreement. Any amounts remaining in the Bond Fund (first, from the proceeds of the Credit Facility, and second, from the moneys provided by or on behalf of the Company) after payment in full of the principal or redemption price of and interest on the Bonds (or provision for payment thereof) and payment of any outstanding fees and expenses of the Trustee (including its reasonable attorney fees and expenses) will be paid, first, to the Credit Facility Issuer, to the extent of any amounts that the Company owes the Credit Facility Issuer pursuant to the Reimbursement Agreement and, second, to the Company. Any amounts remaining in the Bond Fund (i) after all of the outstanding Bonds have been paid and discharged, (ii) after payment of all fees, charges and expenses to the Issuer, the Trustee, the Registrar and the Paying Agent and of all other amounts required to be paid under the Indenture and the Loan Agreement and (iii) after the receipt by the Trustee of the written request of the Company for such payment, will be paid to the Credit Facility Issuer, if any, to the extent of any amounts that the Company owes to such Credit Facility Issuer pursuant to the Reimbursement Agreement, and then to the Company to the extent that those moneys are in excess of the amounts necessary to effect the payment and discharge of the outstanding Bonds.

The Rebate Fund

A Rebate Fund has been created by the Indenture (the "Rebate Fund") and will be maintained as a separate fund free and clear of the lien of the Indenture. The Issuer, the Trustee and the Company have agreed to comply with all rebate requirements of the Code and, in particular, the Company has agreed that if necessary, it will deposit in the Rebate Fund any such amount as is required under the Code. However, the Issuer, the Trustee and the Company may disregard the Rebate Fund provisions to the extent that they receive an opinion of Bond Counsel that such failure to comply will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes.

Discharge of Indenture

When all the Bonds and all fees and charges accrued and to accrue of the Trustee and the Paying Agent have been paid or provided for, and when proper notice has been given to the Bondholders or the Trustee that the proper amounts have been so paid or provided for, and if the Issuer is not in default in any other respect under the Indenture, the Indenture will become null and void. The Bonds will be deemed to have been paid and discharged when there have been irrevocably deposited with the Trustee moneys sufficient to pay the principal, premium, if any, and accrued interest on such Bonds to the due date (whether such date be by reason of maturity or upon redemption) or, in lieu thereof, Governmental Obligations have been deposited which mature in such amounts and at such times as will provide the funds necessary to so pay such Bonds, and when all reasonable and necessary fees and expenses of the Trustee, the Tender Agent, the Authenticating Agent, the Bond Registrar and the Paying Agent have been paid or provided for.

Notwithstanding anything to the contrary, if any Bonds are rated by a rating service, no such Bonds will be deemed to have been paid and discharged by reason of any deposit pursuant to the Indenture, unless each such rating service has confirmed in writing to the Trustee that its rating will not be withdrawn or lowered as a result of any such deposit.

So long as the Company owes any amounts to the Credit Facility Issuer, if any, pursuant to the Reimbursement Agreement: (A) the lien of the Indenture may not be discharged; (B) such Credit Facility Issuer shall be subrogated to the extent of such amounts owed by the Company to such Credit Facility Issuer to all rights of the Bondholders to enforce the payment of the Bonds from the revenues and all other rights of the Bondholders under the Bonds, the Indenture and the Loan Agreement; (C) the Bondholders will be deemed paid to the extent of money drawn by the Trustee under the Credit Facility; and (D) subject to the Indenture, the Trustee will sign, execute and deliver all documents or instruments and do all things that may be reasonably required by the Credit Facility Issuer to effect the Credit Facility Issuer's subrogation of rights of enforcement and remedies set forth in the Indenture.

Defaults and Remedies

Each of the following events constitutes an "Event of Default" under the Indenture:

(a) Failure to make payment of any installment of interest on any Bond, (i) if such Bond bears interest at other than the Long Term Rate, within a period of one Business Day from the due date and (ii) if such Bond bears interest at the Long Term Rate, within a period of five Business Days from the date due;

(b) Failure to make punctual payment of the principal of, or premium, if any, on any Bond on the due date, whether at the stated maturity thereof, or upon proceedings for redemption, or upon the maturity thereof by declaration or if payment of the purchase price of any Bond required to be purchased pursuant to the Indenture is not made when such payment has become due and payable;

(c) Failure of the Issuer to perform or observe any other of the covenants, agreements or conditions in the Indenture or in the Bonds which failure continues for a period of 30 days after written notice by the Trustee, provided, however, that if such failure is capable of being cured, but cannot be cured in such 30-day period, it will not constitute an Event of Default under the Indenture if corrective action in respect of such failure is instituted within such 30-day period and is being diligently pursued;

(d) The occurrence of an "Event of Default" under the Loan Agreement (see "Summary of the Loan Agreement — Events of Default");

(e) written notice from the Credit Facility Issuer to the Trustee of an event of default under the Reimbursement Agreement, by reason of which the Trustee has been directed to accelerate the Bonds; or

(f) if a Credit Facility is then held by the Trustee, on or before the close of business on the tenth calendar day following the honoring of a drawing under such Credit Facility to pay interest on the Bonds on an Interest Payment Date, written notice from the Credit Facility Issuer to the Trustee that the interest component of the Credit Facility will not be reinstated.

Upon the occurrence of an Event of Default under clauses (a), (b), (e) or (f) above, the Trustee must: (i) declare the principal of all Bonds and interest accrued thereon to be immediately due and payable; (ii) declare all payments under the Loan Agreement to be immediately due and payable and enforce each and every other right granted to the Issuer under the Loan Agreement for the benefit of the Bondholders; and (iii) if a Credit Facility securing the Bonds is in effect, make an immediate drawing under the Credit Facility in accordance with its terms and deposit the proceeds of such drawing in the Bond Fund pending application to the payment of principal of the Bonds, subject to the provisions of the Indenture reserving to the Credit Facility Issuer the right to direct default proceedings and providing for termination of default proceedings upon certain occurrences.

Interest on the Bonds will cease to accrue on the date of issuance of the declaration of acceleration of payment of principal and interest on the Bonds.

In exercising such rights, the Trustee will take any action that, in the judgment of the Trustee, would best serve the interests of the registered owners. Upon the occurrence of an Event of Default under the Indenture, the Trustee may also proceed to pursue any available remedy by suit at law or in equity to enforce the payment of the principal of, premium, if any, and interest on the Bonds then outstanding.

If the Trustee recovers any moneys following an Event of Default, unless the principal of the Bonds has been declared due and payable, all such moneys will be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and the payment of any sums due and payable to the United States pursuant to Section 148(f) of the Code, (ii) to the payment of all interest then due on the Bonds and (iii) to the payment of unpaid principal and premium, if any, of the Bonds. If the principal of the Bonds has become due or has been accelerated, such moneys will be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and (ii) to the payment of principal of and interest then due and unpaid on the Bonds. In each case, however, Trustee and Paying Agent fees or costs will not be payable from moneys derived from Credit Facility drawings, any remarketing proceeds or moneys constituting certain Available Moneys under the Indenture.

No Bondholder may institute any suit or proceeding in equity or at law for the enforcement of the Indenture unless an Event of Default has occurred of which the Trustee has been notified or is deemed to have notice, and registered owners holding not less than 25% in aggregate principal amount of Bonds then outstanding have made written request to the Trustee to proceed to exercise the powers granted under the Indenture or to institute such action in their own name and the Trustee fails or refuses to exercise its powers within a reasonable time after receipt of indemnity satisfactory to it.

Any judgment against the Issuer pursuant to the exercise of rights under the Indenture will be enforceable only against specific assigned payments, funds and accounts under the Indenture in the hands of the Trustee. No deficiency judgment will be authorized against the general credit of the Issuer.

No default under paragraph (c) above will constitute an Event of Default until actual notice is given to the Issuer and the Company by the Trustee or to the Issuer, the Company and the Trustee by the registered owners holding not less than 25% in aggregate principal amount of all Bonds outstanding and the Issuer and the Company have had thirty days after such notice to correct the default and failed to do so. If the default is such that it cannot be corrected within the applicable period but is capable of being cured, it will not constitute an Event of Default if corrective action is instituted by the Issuer or the Company within the applicable period and diligently pursued until the default is corrected.

Notwithstanding the foregoing, in addition to the rights of the Trustee and the Bondholders to direct proceedings as described above, if a Credit Facility is in effect, for so long as such Credit Facility is outstanding and the Credit Facility Issuer is not in default in its duties under the Indenture or the Credit Facility, the Credit Facility Issuer issuing will have the absolute right to direct all proceedings on behalf of the Bondholders of the Bonds. Additionally, if the Event of Default which has occurred is an Event of Default under paragraphs (e) or (f) above, the Credit Facility Issuer, if any, will have no right to direct the Trustee or the Bondholders with respect to any matters, including remedies, and the holders of a majority in aggregate principal amount of the Bonds then outstanding, will have the right, at any time, by an instrument or instruments in writing executed and delivered to the Trustee, to direct the time, method and place of conducting all proceedings to be taken in connection with the enforcement of the terms and conditions of the Indenture, or for the appointment of a receiver or any other proceedings hereunder; provided, that such direction shall not be otherwise than in accordance with the provisions of law and of the Indenture.

If an Event of Default has occurred under the Indenture due to failure by the Credit Facility Issuer, if any, to honor a properly presented and conforming drawing by the Trustee under the Credit Facility then in effect in accordance with the terms thereof, all obligations of the Trustee to the Credit Facility Issuer and all rights of such Credit Facility Issuer under the Indenture will be suspended until the earlier of the cure of such failure or all of the Bonds have been paid in full.

Waiver of Events of Default

Except as provided below, the Trustee may in its discretion waive any Event of Default under the Indenture and will do so upon the written request of the registered owners holding a majority in principal amount of all Bonds then outstanding. If, after the principal of all Bonds then outstanding have been declared to be due and payable as a result of a default under the Indenture and prior to any judgment or decree for the appointment of a receiver or for the payment of the moneys due has been obtained or entered, (i) the Company causes to be deposited with the Trustee a sum sufficient to pay all matured installments of interest upon all Bonds and the principal of and premium, if any, on any and all Bonds which would become due otherwise than by reason of such declaration (with interest thereon as provided in the Indenture) and the expenses of the Trustee in connection with such default and (ii) all Events of Default under the Indenture (other than nonpayment of the principal of Bonds due by such declaration) have been remedied, then such Event of Default will be deemed waived and such declaration and its consequences rescinded and annulled by the Trustee. Such waiver, rescission and annulment will be binding upon all Bondholders. No such waiver, rescission and annulment will extend to or affect any subsequent Event of Default or impair any right or remedy consequent thereon.

The Trustee may not waive any default under clauses (e) or (f) unless the Trustee has received in writing from the Credit Facility Issuer a written notice of full reinstatement of the full amount of the Credit Facility and a written rescission of the notice of the Event of Default.

Notwithstanding the foregoing, nothing in the Indenture will affect the right of a registered owner to enforce the payment of principal of, premium, if any, and interest on the Bonds after the maturity thereof.

Supplemental Indentures

The Issuer and the Trustee may enter into indentures supplemental to the Indenture without the consent of or notice to the Bondholders in order (i) to cure any ambiguity or formal defect or omission in the Indenture, (ii) to grant to or confer upon the Trustee, as may lawfully be granted, additional rights, remedies, powers or authorities for the benefit of the Bondholders, (iii) to subject to the Indenture additional revenues, properties or collateral, (iv) to permit qualification of the Indenture under any federal statute or state blue sky law, (v) to add additional covenants and agreements of the Issuer for the protection of the Bondholders or to surrender or limit any rights, powers or authorities reserved to or conferred upon the Issuer, (vi) to make any other modification or change to the Indenture which, in the sole judgment of the Trustee, does not adversely affect the Trustee or any Bondholder, (vii) to make other amendments not otherwise permitted by (i), (ii), (iii), (iv) or (vi) of this paragraph to provisions relating to federal income tax matters under the Code or other relevant provisions if, in the opinion of Bond Counsel, those amendments would not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, (viii) to make any modifications or changes to the Indenture necessary to provide the securing of a Credit Facility or Alternate Credit Facility or any liquidity or credit support of any kind for the security of the Bonds (including without limitation any line of credit, letter of credit, guaranty agreement or insurance coverage), including any modifications of the Indenture or the Agreement necessary to upgrade or maintain the then applicable ratings on the Bonds or (ix) to permit the issuance of the Bonds in other than book-entry-only form or to provide changes to or for the book-entry system.

Subject to the consent of the Credit Facility Issuer, if any, exclusive of supplemental indentures for the purposes set forth in the preceding paragraph, the consent of registered owners holding a majority in aggregate principal amount of all Bonds then outstanding is required to approve any supplemental indenture, except no such supplemental indenture may permit, without the consent of all of the registered owners of the Bonds then outstanding, (i) an extension of the maturity of the principal of or the interest on any Bond issued under the Indenture or a reduction in the principal amount of any Bond or the rate of interest or time of redemption or redemption premium thereon, (ii) a privilege or priority of any Bond or Bonds over any other Bond or Bonds, (iii) a reduction in the aggregate principal amount of the Bonds required for consent to such supplemental indenture or (iv) the deprivation of any registered owners of the lien of the Indenture.

If at any time the Issuer requests the Trustee to enter into any supplemental indenture requiring the consent of the registered owners of the Bonds, the Trustee, upon being satisfactorily indemnified with respect to expenses, must notify all such registered owners. Such notice must set forth the nature of the proposed supplemental indenture and must state that copies thereof are on file at the principal office of the Trustee for inspection. If, within sixty days (or such longer period as prescribed by the Issuer or the Company) following the mailing of such notice, the registered owners holding the requisite amount of the Bonds outstanding have consented to the execution thereof, no Bondholder will have any right to object or question the execution thereof.

No supplemental indenture will become effective unless the Company consents to the execution and delivery of such supplemental indenture. The Company will be deemed to have consented to the execution and delivery of any supplemental indenture if the Trustee does not receive a notice of protest or objection signed by the Company on or before 4:30 p.m., local time in the city in which the principal office of the Trustee is located, on the fifteenth day after the mailing to the Company of a notice of the proposed changes and a copy of the proposed supplemental indenture.

Notwithstanding the foregoing, any Supplemental Indenture that requires the consent of the Bondholders that (i) is to become effective while a Credit Facility is in place or while any amounts are outstanding under any Reimbursement Agreement and (ii) adversely affects the Credit Facility Issuer will not become effective unless and until the Credit Facility Issuer consents in writing to the execution and delivery of such Supplemental Indenture.

Cancellation of Credit Facility; Delivery of Alternate Credit Facility

The Trustee will, at the written direction of the Company but subject to the conditions described in this paragraph and the receipt of an Opinion of Bond Counsel stating that the cancellation of such Credit Facility is authorized under the Indenture and under the Act and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, cancel any Credit Facility in accordance with the terms thereof which cancellation may be without substitution therefor or replacement thereof; provided, that any such cancellation will not become effective, surrender of such Credit Facility will not take place and that Credit Facility will not terminate, in any event, until (i) payment by the Credit Facility Issuer has been made for any and all drawings by the Trustee effected on or before such cancellation date (including, if applicable, any drawings for payment of the purchase price of Bonds to be purchased pursuant to the Indenture in connection with such cancellation) and (ii) if the Bonds are in an Long Term Rate Period, only if the then current Long Term Rate Period for the Bonds is ending on, or the Bonds are subject to optional redemption on, the Interest Payment Date immediately preceding the date of such cancellation. Upon written notice given by the Company to the Trustee at least 20 days (35 days if the Bonds are bearing interest at the Long Term Rate) prior to the date of cancellation of any Credit Facility of such cancellation and the effective date of such cancellation, the Trustee will surrender such Credit Facility to the Credit Facility Issuer by which it was issued on or promptly after the effective date of such cancellation in accordance with its terms; provided, that such notice will not be given in any event, if the purchase price of any Bonds to be purchased pursuant to the Indenture in connection with such cancellation includes any premium unless the Company has certified in such notice that the Trustee can draw under a Credit Facility (other than any Alternate Credit Facility being delivered in connection with such cancellation) on the purchase date related to such purchase of Bonds in an aggregate amount sufficient to pay the premium due upon such purchase of Bonds on such purchase date.

The Company may, at its option, provide for the delivery to the Trustee of an Alternate Credit Facility in replacement of any Credit Facility then in effect. At least 20 days (35 days if the Interest Rate on the Bonds is a Long Term Rate) prior to the date of delivery of an Alternate Credit Facility to the Trustee, the Company must give notice, which notice will also be given to the Remarketing Agent, of such replacement to the Trustee, together with an Opinion of Bond Counsel to the effect that the delivery of such Alternate Credit Facility to the Trustee is authorized under the Indenture and the Act and complies with the terms thereof and that the delivery of such Alternate Credit Facility will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. The Trustee will then accept such Alternate Credit Facility and surrender the previously held Credit Facility, if any, to the previous Credit Facility Issuer for cancellation promptly on or after the 5th day after the Alternate Credit Facility becomes effective; provided, however, that such Alternate Credit Facility must become effective on an Interest Payment Date and, if the Bonds are in a Long Term Rate Period, such Alternate Credit Facility may only become effective on either the last Interest Payment Date for such Long Term Rate Period or an Interest Payment Date on which the Bonds are subject to optional redemption. The notice given to the Trustee shall also be given to the Issuer, the then current Credit Facility Issuer, Moody's, if the Bonds are then rated by Moody's, and S&P, if the Bonds are then rated by S&P; provided that the notice will not be given if the purchase price of any Bonds to be purchased pursuant to the Indenture in connection with such cancellation includes any premium unless the Company has certified in such notice that the Trustee can draw under a Credit Facility then in effect on the purchase date related to such purchase of Bonds in an aggregate amount sufficient to pay the premium due upon such purchase of Bonds on such purchase date and until payment under the Credit Facility to be surrendered shall have been made for any and all drawings by the Trustee effected on or before the date of such surrender for cancellation (including, if applicable, any drawings for payment of the purchase price of Bonds to be purchased pursuant to the Indenture in connection with such cancellation).

Any Alternate Credit Facility delivered to the Trustee must be accompanied by an opinion of counsel to the issuer or provider of such Credit Facility stating that such Credit Facility is a legal, valid, binding and enforceable obligation of such issuer or obligor in accordance with its terms.

The Bonds will be subject to mandatory tender for purchase on the date of cancellation of a Credit Facility and on the date of the delivery of an Alternate Credit Facility. See "Summary of the Bonds — Mandatory Purchases of Bonds."

Enforceability of Remedies

The remedies available to the Trustee, the Issuer and the owners upon an event of default under the Loan Agreement or the Indenture are in many respects dependent upon judicial actions which are often subject to discretion and delay. Under existing constitutional and statutory law and judicial decisions, the remedies specified by the Loan Agreement or the Indenture may not be readily available or may be limited. The various legal opinions to be delivered concurrently with the delivery of the Bonds will be qualified as to the enforceability of the various legal instruments by limitations imposed by principles of equity, bankruptcy, reorganization, insolvency, moratorium or other similar laws affecting the rights of creditors generally.

Reoffering

Subject to the terms and conditions of the Remarketing and Bond Purchase Agreement (the "Remarketing Agreement"), between the Company and Banc of America Securities LLC, as Remarketing Agent, the Remarketing Agent has agreed to purchase and reoffer the Bonds delivered to the Paying Agent for purchase, at a price equal to 100% of the principal amount of the Bonds, plus accrued interest (if any), and in connection therewith will receive compensation in the amount of $135,000, plus reimbursement of certain expenses. Under the terms of the Remarketing Agreement, the Company has agreed to indemnify the Remarketing Agent against certain civil liabilities, including liabilities under federal securities laws.

In the ordinary course of its business, the Remarketing Agent and certain of its affiliates, have engaged, and may in the future engage, in investment banking or commercial banking transactions with the Company.

Tax Treatment

On each of February 23, 2007, the date of original issuance and delivery of the 2006 Series B Bonds, and October 17, 2008, the date of original issuance and delivery of the 2008 Series A Bonds, Bond Counsel delivered its opinions stating that under existing law, including current statutes, regulations, administrative rulings and official interpretations, subject to the qualifications and exceptions set forth below, interest on the Bonds would be excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion would be expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the applicable Project or a "related person" as such terms are used in Section 147(a) of the Code. Interest on the Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. Bond Counsel further opined that, subject to the assumptions stated in the preceding sentence, (i) interest on the Bonds would be excluded from gross income of the owners thereof for Kentucky income tax purposes and (ii) the Bonds would be exempt from all ad valorem taxes in Kentucky. Such opinions have not been updated as of the date hereof and no continuing tax exemption opinions are expressed by Bond Counsel.

Bond Counsel also will deliver opinions in connection with this reoffering to the effect that the conversion of the interest rate on the Bonds to the Weekly Rate and the delivery of the Letter of Credit (i) is authorized or permitted by Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act") and the Indenture and (ii) will not adversely affect the validity of the Bonds or any exclusion from gross income of interest on the Bonds for federal income tax purposes to which interest on the Bonds would otherwise be entitled.

The opinions of Bond Counsel as to the excludability of interest from gross income for federal income tax purposes were based upon and assumed the accuracy of certain representations of facts and circumstances, including with respect to the Projects, which were within the knowledge of the Company and compliance by the Company with certain covenants and undertakings set forth in the proceedings authorizing the Bonds which are intended to assure that the Bonds are and will remain obligations the interest on which is not includable in gross income of the recipients thereof under the law in effect on the date of such opinion. Bond Counsel did not independently verify the accuracy of the certifications and representations made by the Company and the Issuer. On the date of the applicable opinions and subsequent to the original delivery of the 2006 Series B Bonds on February 23, 2007 and the 2008 Series A Bonds on October 17, 2008, as applicable, such representations of facts and circumstances must be accurate and such covenants and undertakings must continue to be complied with in order that interest on the Bonds be and remain excludable from gross income of the recipients thereof for federal income tax purposes under existing law. Bond Counsel expressed no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents other than with the approval of Bond Counsel is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability.

Bond Counsel further opined that the Code prescribed a number of qualifications and conditions for the interest on state and local government obligations to be and to remain excluded from gross income for federal income tax purposes, some of which, including provisions for potential payments by the Issuers to the federal government, require future or continued compliance after issuance of the Bonds in order for the interest to be and to continue to be so excluded from the date of issuance. Noncompliance with certain of these requirements by the Company or the Issuer with respect to the Bonds could cause the interest on the Bonds to be included in gross income for federal income tax purposes and to be subject to federal income taxation retroactively to the date of their issuance. The Company and the Issuer each covenanted to take all actions required of each to assure that the interest on the Bonds shall be and remain excluded from gross income for federal income tax purposes, and not to take any actions that would adversely affect that exclusion.

The opinions of Bond Counsel as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds was subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, Bond Counsel expressed no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Owners of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income tax credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of Section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income. Prospective purchasers of the Bonds should consult their own tax advisors regarding such matters and any other tax consequences of holding the Bonds.

From time to time, there are legislative proposals in Congress which, if enacted, could alter or amend one or more of the federal tax matters referred to above or could adversely affect the market value of the Bonds. It cannot be predicted whether or in what form any such proposal might be enacted or whether, if enacted, it would apply to obligations (such as the Bonds) issued prior to enactment.

The opinions of Bond Counsel relating to conversion of the Bonds in substantially the forms in which they are expected to be delivered on the Conversion Date, redated to the Conversion Date, are attached as Appendices B-3 and B-4.

Legal Matters

Certain legal matters in connection with the Conversion and reoffering of the Bonds will be passed upon by Stoll Keenon Ogden, Bond Counsel. Bond Counsel has in the past, and may in the future, act as counsel to the Company with respect to certain matters. Certain legal matters will be passed upon for the Issuer by its County Attorney. Certain legal matters will be passed upon for the Company by Jones Day, Chicago, Illinois, and John R. McCall, Esq., Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer for the Company. Winston & Strawn LLP, Chicago, Illinois, will pass upon certain legal matters for the Remarketing Agent.

Continuing Disclosure

Because the Bonds are special and limited obligations of the Issuer, the Issuer is not an "obligated person" for purposes of Rule 15c2-12 (the "Rule") promulgated by the SEC under the Exchange Act, and does not have any continuing obligations thereunder. Accordingly, the Issuer will not provide any continuing disclosure information with respect to the Bonds or the Issuer.

2006 Series B Bonds

In order to enable the Remarketing Agent to comply with the requirements of the Rule, the Company has covenanted in a continuing disclosure undertaking agreement delivered to the Trustee for the benefit of the holders of the 2006 Series B Bonds (the "Continuing Disclosure Agreement") to provide certain continuing disclosure for the benefit of the holders of such Bonds. Under its Continuing Disclosure Agreement, the Company has covenanted to take the following actions:

(a) The Company will provide to each nationally recognized municipal securities information repository ("NRMSIR"), recognized by the SEC pursuant to the Rule, and the state information depository, if any, of the Commonwealth of Kentucky (a "SID" and, together with the NRMSIR, a "Repository") recognized by the SEC (1) annual financial information of the type set forth in Appendix A to this Reoffering Circular (including any information incorporated by reference therein) and (2) audited financial statements prepared in accordance with generally accepted accounting principles, in each case not later than 120 days after the end of the Company's fiscal year.

(b) The Company will file in a timely manner with each NRMSIR or the Municipal Securities Rulemaking Board, and with the SID, if any, notice of the occurrence of any of the following events (if applicable) with respect to the 2006 Series B Bonds, if material: (i) principal and interest payment delinquencies; (ii) non-payment related defaults; (iii) any unscheduled draws on debt service reserves reflecting financial difficulties; (iv) unscheduled draws on credit enhancement facilities reflecting financial difficulties; (v) substitution of credit or liquidity providers, or their failure to perform; (vi) adverse tax opinions or events affecting the tax-exempt status of the 2006 Series B Bonds; (vii) modifications to rights of the holders of the 2006 Series B Bonds; (viii) the giving of notice of optional or unscheduled redemption of any 2006 Series B Bonds; (ix) defeasance of the 2006 Series B Bonds or any portion thereof; (x) release, substitution, or sale of property securing repayment of the 2006 Series B Bonds; and (xi) rating changes with respect to the 2006 Series B Bonds or the Company or any obligated person, within the meaning of the Rule.

(c) The Company will file in a timely manner with each Repository notice of a failure by the Company to file any of the notices or reports referred to in paragraphs (a) and (b) above by the due date.

The Company may amend its Continuing Disclosure Agreement (and the Trustee shall agree to any amendment so requested by the Company that does not change the duties of the Trustee thereunder) or waive any provision thereof, but only with a change in circumstances that arises from a change in legal requirements, change in law, or change in the nature or status of the Company with respect to the 2006 Series B Bonds or the type of business conducted by the Company; provided that the undertaking, as amended or following such waiver, would have complied with the requirements of the Rule on the date of issuance of the 2006 Series B Bonds, after taking into account any amendments to the Rule as well as any change in circumstances, and the amendment or waiver does not materially impair the interests of the holders of the 2006 Series B Bonds to which such undertaking relates, in the opinion of the Trustee or counsel expert in federal securities laws acceptable to both the Company and the Trustee, or is approved by the Beneficial Owners of a majority in aggregate principal amount of the outstanding 2006 Series B Bonds. The Company acknowledges that its undertakings pursuant to the Rule described under this heading are intended to be for the benefit for the holders of the 2006 Series B Bonds and shall be enforceable by the holders of those 2006 Series B Bonds or by the Trustee on behalf of such holders. Any breach by the Company of these undertakings pursuant to the Rule will not constitute an event of default under the Indentures, the Loan Agreements or the 2006 Series B Bonds.

2008 Series A Bonds

The Rule generally requires that “obligated persons” such as the Company agree to provide (i) continuing disclosure on an annual basis of certain financial information and operating data and (ii) notices of certain specified events that could affect the credit underlying the payment obligations of the securities. However, offerings of securities that are subject purchase by the issuer on the demand of the holder, such as will be the case with respect to the 2008 Series A Bonds while bearing interest in a Daily Rate Period or a Weekly Rate Period, or while bearing interest in a Flexible Rate Period of 270 days or less, are exempt from these requirements. If the 2008 Series A Bonds are remarketed in a mode other than the Daily Rate Period, the Weekly Rate Period or the Flexible Rate Period, the Company may in the future become subject to these continuing disclosure obligations of the Rule with respect to such 2008 Series A Bonds.

This Reoffering Circular has been duly approved, executed and delivered by the Company.

KENTUCKY UTILITIES COMPANY

By: /s/ Daniel K. Arbough
Daniel K. Arbough
Treasurer

Appendix A

[DELETED AND REPLACED – SEE APPENDIX A TO SUPPLEMENT DATED MAY 2, 2011]

APPENDIX B

Opinions of Bond Counsel and
Forms of Conversion Opinions of Bond Counsel

APPENDIX B-1

Opinion of Bond Counsel dated February 23, 2007 relating to the 2006 Series B Bonds

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PLLC

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February 23, 2007

Re: $54,000,000 County of Carroll, Kentucky, Environmental Facilities Revenue Refunding Bonds, 2006 Series B (Kentucky Utilities Company Project)

We hereby certify that we have examined certified copies of the proceedings of record of the County of Carroll, Kentucky (the "County"), acting by and through its Fiscal Court as its duly authorized governing body, preliminary to and in connection with the issuance by the County of its Environmental Facilities Revenue Refunding Bonds, 2006 Series B (Kentucky Utilities Company Project), dated their date of issuance, in the aggregate principal amount of $54,000,000 (the "Bonds"). The Bonds are issued under the provisions of Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act"), for the purpose of providing funds which will be used, with other funds provided by Kentucky Utilities Company (the "Company") for the current refunding of $54,000,000 aggregate principal amount of the County's Collateralized Solid Waste Disposal Facilities Revenue Bonds (Kentucky Utilities Company Project) 1994 Series A, dated November 23, 1994 (the "Prior Bonds"), which were issued for the purpose of financing a portion of the costs of construction, acquisition, installation and equipping of certain solid waste disposal facilities to serve the Ghent Generating Station of the Company in Carroll County, Kentucky (the "Project") in order to provide for the collection, storage, treatment, processing and final disposal of solid wastes, as provided by the Act.

The Bonds mature on October 1, 2034 and bear interest initially at the Dutch Auction Rate, as defined in the Indenture, hereinafter described, subject to change as provided in such Indenture. The Bonds will be subject to optional and mandatory redemption prior to maturity at the times, in the manner and upon the terms set forth in the Bonds. From such examination of the proceedings of the Fiscal Court of the County referred to above and from an examination of the Act, we are of the opinion that the County is duly authorized and empowered to issue the Bonds under the laws of the Commonwealth of Kentucky now in force.

We have examined an executed counterpart of a certain Loan Agreement, dated as of October 1, 2006 (the "Loan Agreement"), between the County and the Company and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Loan Agreement, pursuant to which the County has agreed to issue the Bonds and to lend the proceeds thereof to the Company to provide funds to pay and discharge, with other funds provided by the Company, the Prior Bonds.

The Company has agreed to make Loan payments to the Trustee at times and in amounts fully adequate to pay maturing principal of, interest on and redemption premium, if any, on the Bonds as same become due and payable. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Loan Agreement; that the Loan Agreement has been duly authorized, executed and delivered by the County; and that the Loan Agreement is a legal, valid and binding obligation of the County, enforceable in accordance with its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

We have also examined an executed counterpart of a certain Indenture of Trust, dated as of October 1, 2006 (the "Indenture"), by and between the County and Deutsche Bank Trust Company Americas, as trustee (the "Trustee"), securing the Bonds and setting forth the covenants and undertakings of the County in connection with the Bonds and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Indenture. Pursuant to the Indenture, certain of the County's rights under the Loan Agreement, including the right to receive payments thereunder, and all moneys and securities held by the Trustee in accordance with the Indenture (except moneys and securities in the Rebate Fund created thereby) have been assigned to the Trustee, as security for the holders of the Bonds. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Indenture; that the Indenture has been duly authorized, executed and delivered by the County; and that the Indenture is a legal, valid and binding obligation upon the parties thereto according to its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

In our opinion the Bonds have been validly authorized, executed and issued in accordance with the laws of the Commonwealth of Kentucky now in full force and effect, and constitute legal, valid and binding special obligations of the County entitled to the benefit of the security provided by the Indenture and enforceable in accordance with their terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought. The Bonds are payable by the County solely and only from payments and other amounts derived from the Loan Agreement and as provided in the Indenture.

In our opinion, under existing laws, including current statutes, regulations, administrative rulings and official interpretations by the Internal Revenue Service, subject to the exceptions and qualifications contained in the succeeding paragraphs, interest on the Bonds is excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion is expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person," as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on the Bonds is a separate item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. In arriving at this opinion, we have relied upon representations, factual statements and certifications of the Company with respect to certain material facts which are solely within the Company's knowledge in reaching our conclusion, inter alia, that not less than 95% of the net proceeds of the Prior Bonds were used to finance solid waste disposal facilities qualified for financing under Section 142(a)(6) of the Code and the Act. Further, in arriving at the opinion set forth in this paragraph as to the exclusion from gross income of interest on the Bonds, we have assumed and this opinion is conditioned on, the accuracy of and continuing compliance by the Company and the County with representations and covenants set forth in the Loan Agreement and the Indenture which are intended to assure compliance with certain tax-exempt interest provisions of the Code. Such representations and covenants must be accurate and must be complied with subsequent to the issuance of the Bonds in order that interest on the Bonds be excluded from gross income for federal income tax purposes. Failure to comply with certain of such representations and covenants in respect of the Bonds subsequent to the issuance of the Bonds could cause the interest thereon to be included in gross income for federal income tax purposes retroactively to the date of issuance of the Bonds. We express no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents (other than with approval of this firm) is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability. We are further of the opinion that interest on the Bonds is excluded from gross income of the recipients thereof for Kentucky income tax purposes and that the Bonds are exempt from ad valorem taxation by the Commonwealth of Kentucky and all political subdivisions thereof.

Our opinion as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds is further subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, we express no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Holders of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that, for taxable years beginning after December 31, 1986, property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income.

We have received opinions of John R. McCall, Esq., General Counsel of the Company and Jones Day, Chicago, Illinois, counsel to the Company, of even date herewith. In rendering this opinion, we have relied upon said opinions with respect to the matters therein. We have also received an opinion of even date herewith of Hon. James C. Monk, County Attorney of the County and relied upon said opinion with respect to the matters therein. Said opinions are in forms satisfactory to us as to both scope and content.

We express no opinion as to the title to, the description of, or the existence or priority of any liens, charges or encumbrances on, the Project.

In rendering the foregoing opinions, we are passing upon only those matters specifically set forth in such opinions and are not passing upon the investment quality of the Bonds or the accuracy or completeness of any statements made in connection with any offer or sale thereof. The opinions herein are expressed as of the date hereof and we assume no obligation to supplement or update such opinions to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We are members of the Bar of the Commonwealth of Kentucky and do not purport to be experts on the laws of any jurisdiction other than the Commonwealth of Kentucky and the United States of America, and we express no opinion as to the laws of any jurisdiction other than those specified.

Respectfully submitted,

Stoll Keenon Ogden PLLC

STOLL KEENON OGDEN PLLC

APPENDIX B-2

Opinion of Bond Counsel dated October 17, 2008 relating to the 2008 Series A Bonds

STOLL·KEENON·OGDEN
PLLC

2000 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202-2828
502-333-6000
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October 17, 2008

Re: $77,947,405 "County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2008 Series A (Kentucky Utilities Company Project)"

We hereby certify that we have examined certified copies of the proceedings of record of the County of Carroll, Kentucky (the "County"), acting by and through its Fiscal Court as its duly authorized governing body, preliminary to and in connection with the issuance by the County of its Environmental Facilities Revenue Bonds, 2008 Series A (Kentucky Utilities Company Project), dated their date of issuance, in the aggregate principal amount of $77,947,405 (the "Bonds"). The Bonds are issued under the provisions of Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act"), for the purpose of providing funds which will be used, with other funds provided by Kentucky Utilities Company (the "Company") for the purposes of (i) financing a portion of the costs of construction, acquisition, installation and equipping of certain solid waste disposal facilities to serve the Ghent Generating Station of the Company in Carroll County, Kentucky (the "Construction Project") in order to provide for the collection, storage, treatment and final disposal of solid wastes, as provided by the Act in the principal amount of $18,026,265, and (ii) currently refunding (a) $13,266,950 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2005 Series A (Kentucky Utilities Company Project) (the "2005 Series A Bonds"), (b) $13,266,950 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2005 Series B (Kentucky Utilities Company Project) (the "2005 Series B Bonds"), (c) $16,693,620 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2006 Series A (Kentucky Utilities Company Project) (the "2006 Series A Bonds") and (d) $16,693,620 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2006 Series C (Kentucky Utilities Company Project) (the "2006 Series C Bonds" and, together with the 2005 Series A Bonds, the 2005 Series B Bonds and the 2006 Series A Bonds, the "Refunded Bonds"), which were issued for the purpose of financing all or a portion of the qualified costs of acquisition, construction, installation and equipping of certain solid waste disposal facilities to serve the Ghent Generating Station of Company in Carroll County, Kentucky (the "Refunding Project" and, together with the Construction Project, the "Project"), as provided by the Act.

The Bonds mature on February 1, 2032, and bear interest initially at the Flexible Rate, as defined in the Indenture, hereinafter described, subject to change as provided in such Indenture. The Bonds will be subject to optional and mandatory redemption prior to maturity at the times, in the manner and upon the terms set forth in the Bonds. From such examination of the proceedings of the Fiscal Court of the County referred to above and from an examination of the Act, we are of the opinion that the County is duly authorized and empowered to issue the Bonds under the laws of the Commonwealth of Kentucky now in force.

We have examined an executed counterpart of a certain Loan Agreement, dated as of August 1, 2008 (the "Loan Agreement"), between the County and the Company and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Loan Agreement, pursuant to which the County has agreed to issue the Bonds and to lend the proceeds thereof to the Company to provide funds to finance a portion of the costs of the acquisition, construction, installation and equipping of the Construction Project and to pay and discharge with other funds provided by the Company, the Refunded Bonds. The Company has agreed to make Loan payments to the Trustee at times and in amounts fully adequate to pay maturing principal of, interest on and redemption premium, if any, on the Bonds as same become due and payable. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Loan Agreement; that the Loan Agreement has been duly authorized, executed and delivered by the County; and that the Loan Agreement is a legal, valid and binding obligation of the County, enforceable in accordance with its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

We have also examined an executed counterpart of a certain Indenture of Trust, dated as of August 1, 2008 (the "Indenture"), by and between the County and Deutsche Bank Trust Company Americas, as trustee (the "Trustee"), securing the Bonds and setting forth the covenants and undertakings of the County in connection with the Bonds and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Indenture. Pursuant to the Indenture, certain of the County's rights under the Loan Agreement, including the right to receive payments thereunder, and all moneys and securities held by the Trustee in accordance with the Indenture (except moneys and securities in the Rebate Fund created thereby) have been assigned to the Trustee, as security for the holders of the Bonds. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Indenture; that the Indenture has been duly authorized, executed and delivered by the County; and that the Indenture is a legal, valid and binding obligation upon the parties thereto according to its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

In our opinion the Bonds have been validly authorized, executed and issued in accordance with the laws of the Commonwealth of Kentucky now in full force and effect, and constitute legal, valid and binding special obligations of the County entitled to the benefit of the security provided by the Indenture and enforceable in accordance with their terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought. The Bonds are payable by the County solely and only from payments and other amounts derived from the Loan Agreement and as provided in the Indenture.

In our opinion, under existing laws, including current statutes, regulations, administrative rulings and official interpretations by the Internal Revenue Service, subject to the exceptions and qualifications contained in the succeeding paragraphs, (i) interest on the Bonds is excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion is expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person," as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code") and (ii) interest on the Bonds is a separate item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. In arriving at this opinion, we have relied upon representations, factual statements and certifications of the Company with respect to certain material facts which are solely within the Company's knowledge in reaching our conclusion, inter alia, that not less than 95% of the proceeds of the Bonds will be used to finance or refinance solid waste disposal facilities qualified for financing under Section 142(a)(6) of the Code and the Act. Further, in arriving at the opinion set forth in this paragraph as to the exclusion from gross income of interest on the Bonds, we have assumed and this opinion is conditioned on, the accuracy of and continuing compliance by the Company and the County with representations and covenants set forth in the Loan Agreement and the Indenture which are intended to assure compliance with certain tax-exempt interest provisions of the Code. Such representations and covenants must be accurate and must be complied with subsequent to the issuance of the Bonds in order that interest on the Bonds be excluded from gross income for federal income tax purposes. Failure to comply with certain of such representations and covenants in respect of the Bonds subsequent to the issuance of the Bonds could cause the interest thereon to be included in gross income for federal income tax purposes retroactively to the date of issuance of the Bonds. We express no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents (other than with approval of this firm) is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability. We are further of the opinion that interest on the Bonds is excluded from gross income of the recipients thereof for Kentucky income tax purposes and that the Bonds are exempt from ad valorem taxation by the Commonwealth of Kentucky and all political subdivisions thereof.

Our opinion as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds is further subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, we express no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Holders of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that, for taxable years beginning after December 31, 1986, property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of Section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income.

We have received opinions of John R. McCall, Esq., General Counsel of the Company, and Jones Day, Chicago, Illinois, counsel to the Company, of even date herewith. In rendering this opinion, we have relied upon said opinions with respect to the matters therein. We have also received an opinion of even date herewith of Hon. James C. Monk, County Attorney of the County and relied upon said opinion with respect to the matters therein. Said opinions are in forms satisfactory to us as to both scope and content.

We express no opinion as to the title to, the description of, or the existence or priority of any liens, charges or encumbrances on, the Project.

In rendering the foregoing opinions, we are passing upon only those matters specifically set forth in such opinions and are not passing upon the investment quality of the Bonds or the accuracy or completeness of any statements made in connection with any offer or sale thereof. The opinions herein are expressed as of the date hereof and we assume no obligation to supplement or update such opinions to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We are members of the Bar of the Commonwealth of Kentucky and do not purport to be experts on the laws of any jurisdiction other than the Commonwealth of Kentucky and the United States of America, and we express no opinion as to the laws of any jurisdiction other than those specified.

Respectfully submitted,

Stoll Keenon Ogden PLLC

STOLL KEENON OGDEN PLLC

APPENDIX B-3

(Form of Conversion Opinion of Bond Counsel)
(2006 Series B Bonds)

December 19, 2008

County of Carroll, Kentucky
Carrollton, Kentucky 41008

Deutsche Bank Trust Company Americas,
as Trustee
Summit, New Jersey 07901

Re: Conversion to Weekly Rate Period of $54,000,000 "County of Carroll, Kentucky, Environmental Facilities Revenue Refunding Bonds, 2006 Series B (Kentucky Utilities Company Project)"

Ladies and Gentlemen:

This opinion is being furnished in accordance with the requirements of the Indenture of Trust, dated as of October 1, 2006 (the "Indenture"), between the County of Carroll, Kentucky (the "Issuer") and Deutsche Bank Trust Company Americas, as Trustee (the "Trustee"), pertaining to $54,000,000 principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Refunding Bonds, 2006 Series B (Kentucky Utilities Company Project), dated February 23, 2007 (the "Bonds"), in order to satisfy certain requirements of Section 2.02(e)(i) of the Indenture. Pursuant to Section 2.02(e)(i) of the Indenture, the interest rate on the Bonds is being converted from a Dutch Auction Rate to a Weekly Rate effective on December 19, 2008, the Conversion Date. The terms used herein denoted by initial capitals and not otherwise defined shall have the meanings specified in the Indenture.

We have examined the law and such documents and matters as we have deemed necessary to provide this opinion. As to questions of fact material to the opinions expressed herein, we have relied upon the provisions of the Indenture and related documents, and upon representations made to us without undertaking to verify the same by independent investigation.

Based upon the foregoing, as of the date hereof, we are of the opinion that the conversion of the interest rate on the Bonds as described herein (a) is authorized or permitted by the Act and the Indenture and (b) will not adversely affect the validity of the Bonds or any exclusion from gross income for federal income tax purposes to which interest on the Bonds would otherwise be entitled. Interest on the Bonds is not and will not be excluded from gross income during any period when the Bonds are held by the Company or a "related person" of the Company as defined in Section 147(a) of the Internal Revenue Code of 1986, as amended.

In rendering this opinion, we assume, without verifying, that the Issuer and the Company have complied and will comply with all covenants contained in the Indenture, the Loan Agreement between the Issuer and the Company, dated October 1, 2006, and other documents relating to the Bonds. We rendered our approving opinion at the time of the issuance of the

Bonds relating to, among other things, the validity of the Bonds and the exclusion from federal income taxation of interest on the Bonds. We have not been requested to update or continue such opinion and have not undertaken to do so. Accordingly, we do not express any opinion with respect to the Bonds except as set forth above.

Our opinion represents our legal judgment based upon our review of the law and the facts that we deem relevant to render such opinion and is not a guarantee of a result. This opinion is given as of the date hereof and we assume no obligation to review or supplement this opinion to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We express no opinion herein as to the investment quality of the Bonds or the adequacy, accuracy or completeness of any information furnished to any person in connection with any offer or sale of the Bonds.

Respectfully submitted,

STOLL KEENON OGDEN PLLC

APPENDIX B-4

(Form of Conversion Opinion of Bond Counsel)
(2008 Series A Bonds)

December 19, 2008

County of Carroll, Kentucky
Carrollton, Kentucky 41008

Deutsche Bank Trust Company Americas,
as Trustee
Summit, New Jersey 07901

Re: Conversion to Weekly Rate Period of $77,947,405 "County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2008 Series A (Kentucky Utilities Company Project)"

Ladies and Gentlemen:

This opinion is being furnished in accordance with the requirements of the Indenture of Trust, dated as of August 1, 2008 (the "Indenture"), between the County of Carroll, Kentucky (the "Issuer") and Deutsche Bank Trust Company Americas, as Trustee (the "Trustee"), pertaining to $77,947,405 principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2008 Series A (Kentucky Utilities Company Project), dated October 17, 2008 (the "Bonds"), in order to satisfy certain requirements of Section 2.02(e)(i) of the Indenture. Pursuant to Section 2.02(e)(i) of the Indenture, the interest rate on the Bonds is being converted from a Flexible Rate to a Weekly Rate effective on December 19, 2008, the Conversion Date. The terms used herein denoted by initial capitals and not otherwise defined shall have the meanings specified in the Indenture.

We have examined the law and such documents and matters as we have deemed necessary to provide this opinion. As to questions of fact material to the opinions expressed herein, we have relied upon the provisions of the Indenture and related documents, and upon representations made to us without undertaking to verify the same by independent investigation.

Based upon the foregoing, as of the date hereof, we are of the opinion that the conversion of the interest rate on the Bonds as described herein (a) is authorized or permitted by the Act and the Indenture and (b) will not adversely affect the validity of the Bonds or any exclusion from gross income for federal income tax purposes to which interest on the Bonds would otherwise be entitled. Interest on the Bonds is not and will not be excluded from gross income during any period when the Bonds are held by the Company or a "related person" of the Company as defined in Section 147(a) of the Internal Revenue Code of 1986, as amended.

In rendering this opinion, we assume, without verifying, that the Issuer and the Company have complied and will comply with all covenants contained in the Indenture, the Loan Agreement between the Issuer and the Company, dated August 1, 2008, and other documents relating to the Bonds. We rendered our approving opinion at the time of the issuance of the

Bonds relating to, among other things, the validity of the Bonds and the exclusion from federal income taxation of interest on the Bonds. We have not been requested to update or continue such opinion and have not undertaken to do so. Accordingly, we do not express any opinion with respect to the Bonds except as set forth above.

Our opinion represents our legal judgment based upon our review of the law and the facts that we deem relevant to render such opinion and is not a guarantee of a result. This opinion is given as of the date hereof and we assume no obligation to review or supplement this opinion to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We express no opinion herein as to the investment quality of the Bonds or the adequacy, accuracy or completeness of any information furnished to any person in connection with any offer or sale of the Bonds.

Respectfully submitted,

STOLL KEENON OGDEN PLLC

Appendix C

[DELETED AND REPLACED – SEE APPENDIX C TO SUPPLEMENT DATED MAY 2, 2011]

Supplement, dated May 2, 2011 to Reoffering Circular dated December 10, 2008, as supplemented as of December 16, 2008, October 29, 2010 and December 1, 2010 (the "Reoffering Circular")

$50,000,000
County of Carroll, Kentucky
Environmental Facilities Revenue Bonds, 2004 Series A
(Kentucky Utilities Company Project)

Effective as of May 2, 2011, through April 22, 2014 (the Letter of Credit (as defined below) expiration date, subject to extension or earlier termination), payment of the principal of and interest on the above-referenced bonds (the "Bonds") when due will be paid with funds drawn under an irrevocable transferable direct pay letter of credit (the "Letter of Credit") issued by

SUMITOMO MITSUI BANKING CORPORATION, NEW YORK BRANCH

The Letter of Credit will permit the Trustee to draw with respect to the Bonds up to an amount sufficient to pay (i) the principal thereof (or that portion of the purchase price corresponding to principal) plus (ii) interest thereon (or that portion of the purchase price corresponding to interest) up to a maximum rate of 14% per annum for at least 45 days.

The Bonds will continue to bear interest at a Weekly Rate, determined by the Remarketing Agent, BofA Merrill Lynch, in accordance with the Indenture, payable on the first Business Day of each calendar month, commencing on June 1, 2011. The interest rate period, interest rate and Interest Rate Mode will be subject to change under certain conditions, as described in the Reoffering Circular. The Bonds are subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption following a determination of taxability prior to maturity, as described in the Reoffering Circular. The Bonds are subject to mandatory purchase on any date on which the Bonds are converted to a different Interest Rate Mode and upon the expiration of the Letter of Credit or any Alternate Credit Facility.

This supplement contains a description of the Letter of Credit and Sumitomo Mitsui Banking Corporation, New York Branch, the issuer of the Letter of Credit. For purposes of the Reoffering Circular, the Letter of Credit is a "Credit Facility" and Sumitomo Mitsui Banking Corporation, New York Branch is a "Credit Facility Issuer." Except as otherwise specified herein, information in the Reoffering Circular referred to above has not been amended or modified and the information contained herein is qualified by reference to, and should be read in conjunction with, the Reoffering Circular, including information incorporated therein by reference. Terms not otherwise defined herein shall have the meanings ascribed to them in such Reoffering Circular.

The eighth paragraph under the section of the Reoffering Circular captioned "Introductory Statement" is hereby amended to read in its entirety as follows:

Effective May 2, 2011, the Company will cause to be delivered an irrevocable transferable direct pay letter of credit (the "Letter of Credit"), issued by Sumitomo Mitsui Banking Corporation, New York Branch (the "Bank"), to provide for the timely payment of principal of and accrued interest (calculated for at least 45 days at the maximum rate of 14% per annum) on, and purchase price of, the Bonds. The Company will be required to reimburse the Bank for all amounts drawn by the Trustee under the Letter of Credit pursuant to the terms of a certain Reimbursement Agreement, to be dated as of May 2, 2011 (the "Reimbursement Agreement"), between the Company and the Bank. The Letter of Credit will expire on April 22, 2014, unless extended or earlier terminated.

* * * *

The section of the Reoffering Circular captioned "The Letter of Credit" is hereby amended to read in its entirety as follows:

THE LETTER OF CREDIT

The following summarizes certain provisions of the Letter of Credit and the Reimbursement Agreement, to which reference is made for the detailed provisions thereof. Unless otherwise defined in this Reoffering Circular, capitalized terms in the following summary are used as defined in the Letter of Credit and the Reimbursement Agreement. The Company is permitted under the Indenture to deliver an Alternate Credit Facility to replace the Letter of Credit. Any such Alternate Credit Facility must meet certain requirements described in the Indenture.

The Letter of Credit

The Letter of Credit will be an irrevocable transferable direct pay letter of credit issued by the Bank in order to provide additional security for the payment of principal of, purchase

price of, interest on and premium, if applicable, on any date when payments under the Bonds are due, including principal and interest payments and payments upon tender, redemption, acceleration or maturity of the Bonds. The Letter of Credit will provide for direct payments to or upon the order of the Trustee as set forth in the Letter of Credit in amounts sufficient to pay such amounts in accordance with the terms thereof.

The Letter of Credit will be issued in an amount equal to the aggregate principal amount of the outstanding Bonds, plus an amount that represents interest accrued thereon at an assumed maximum rate of 14% per annum for 45 days (the "Credit Amount"). The Trustee, upon compliance with the terms of the Letter of Credit, is authorized to draw up to (a) an amount sufficient (i) to pay principal of the Bonds, when due, whether at maturity or upon redemption or acceleration, and (ii) to pay the portion of the purchase price of the Bonds delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed (a "Liquidity Drawing") equal to the principal amount of the Bonds, plus (b) an amount not to exceed 45 days of accrued interest on the Bonds at an assumed rate of 14% per annum (i) to pay interest on the Bonds, when due, and (ii) to pay the portion of the interest accrued on the Bonds as of any Liquidity Drawing.

The amount available under the Letter of Credit will be automatically reduced by the amount of any drawing thereunder, subject to reinstatement as described below. With respect to a drawing by the Trustee solely to pay interest on the Bonds on an Interest Payment Date, the amount available under the Letter of Credit will be automatically reinstated in the amount of such drawing effective on the earlier of (i) receipt by the Bank from the Company of reimbursement of any drawing solely to pay interest in full or (ii) at the opening of business on the eleventh calendar day after the date the Bank honors such drawing, unless the Trustee has received written notice from the Bank by the tenth calendar day after the date the Bank honors such drawing that the Bank is not so reinstating the available amount due to the Company's failure to reimburse the Bank for such drawing in full, or that an event of default has occurred and is continuing under the $198,309,583.05 Letter of Credit Agreement dated as of April 29, 2011 among the Company, the lenders from time to time thereto, and Banco Bilbao Vizcaya Argentaria, S.A., New York Branch, as Administrative Agent (the "Credit Agreement") and, in either case, directing an acceleration of the Bonds pursuant to the Indenture. With respect to a Liquidity Drawing under the Letter of Credit, the amount available under the Letter of Credit will be automatically reduced by the principal amount of the Bonds purchased with the proceeds of such drawing plus the amount of accrued interest on such Bonds. In the event of the remarketing of the Bonds purchased with the proceeds of a Liquidity Drawing, the amount available under the Letter of Credit will be automatically reinstated upon receipt by the Bank or the Trustee on the Bank's behalf of an amount equal to such principal amount plus accrued interest.

The Letter of Credit will terminate on the earliest to occur of:

(i) the Bank's close of business on April 22, 2014 (such date, as extended from time to time in accordance with the Letter of Credit is defined as the "Stated Expiration Date");

(ii) the Bank's close of business on the date which is five Business Days following the date of receipt by the Bank of a certificate from the Trustee certifying that (a) no Bonds remain Outstanding within the meaning of the Indenture, (b) all drawings required to be made under the Indenture and available under the Letter of Credit have been made and honored, (c) an Alternate Credit Facility has been delivered to the Trustee in accordance with the Indenture to replace the Letter of Credit or (d) all of the outstanding Bonds were converted to Bonds bearing interest at a rate other than the Daily Rate or the Weekly Rate;

(iii) the Bank's close of business on the date of receipt by the Bank of a certificate from the Trustee confirming that the Trustee is required to terminate the Letter of Credit in accordance with the terms of the Indenture;

(iv) the date on which the Bank receives and honors an acceleration drawing certificate; or

(v) the Bank's close of business on the date which is 30 days after receipt by the Trustee of written notice from the Bank of an Event of Default under the Credit Agreement and instructing the Trustee to draw under the Letter of Credit.

Pursuant to the Credit Agreement, the Company is obligated to reimburse the Bank for all amounts drawn under the Letter of Credit, and to pay interest on all such amounts. The Company has also agreed to pay the Bank and the Administrative Agent fees for issuing and maintaining the Letter of Credit.

The Reimbursement Agreement

The Reimbursement Agreement, through incorporation of the terms of the Credit Agreement, imposes various covenants and agreements, including various financial and operating covenants, on the Company. Such covenants include, but are not limited to, covenants relating to (i) inspection of the books and financial records of the Company; (ii) mergers or consolidations; (iii) disposition of assets and (iv) capitalization ratios. Any such covenants may be amended, waived or modified at any time by the Bank and without the consent of the Trustee or the holders of the Bonds. Under certain circumstances, the failure of the Company to comply with such covenants may result in a mandatory tender or acceleration of the Bonds.

An Event of Default under the Credit Agreement will constitute an Event of Default under the Reimbursement Agreement. The following events will constitute an Event of Default under the Credit Agreement:

(i) the Company shall fail to pay when due any principal on any Reimbursement Obligations; or

(ii) the Company shall fail to pay when due any interest on the Reimbursement Obligations, any fee or any other amount payable under the Credit Agreement or under any other Loan Document for five (5) days following the date such payment becomes due thereunder; or

(iii) the Company shall fail to observe or perform certain covenants or agreements contained in the Credit Agreement, including those related to mergers, disposition of assets and capitalization ratios; or

(iv) the Company shall fail to give notice of a Default or Event of Default under the Credit Agreement within a specified number of days following knowledge of such occurrence; or

(v) the Company shall fail to observe or perform any covenant or agreement contained in the Credit Agreement or any other Loan Document (other than those covered above) for thirty (30) days after written notice thereof has been given to the defaulting party by the administrative agent, or at the request of the required lenders; or

(vi) any representation, warranty or certification made by the Company in the Credit Agreement or any other Loan Document or in any certificate, financial statement or other document delivered pursuant hereto or thereto shall prove to have been incorrect in any material respect when made or deemed made; or

(vii) the Company shall (i) fail to pay any principal or interest, regardless of amount, due in respect of any Material Debt beyond any period of grace provided with respect thereto, or (ii) fail to observe or perform any other term, covenant, condition or agreement contained in any agreement or instrument evidencing or governing any such Material Debt beyond any period of grace provided with respect thereto if the effect of any failure referred to in this clause (ii) is to cause, or to permit the holder or holders of such Material Debt or a trustee on its or their behalf to cause, such Material Debt to become due prior to its stated maturity; or

(viii) the Company shall commence a voluntary case or other proceeding seeking liquidation, reorganization or other relief with respect to itself or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any substantial part of its property, or shall consent to any such relief or to the appointment of or taking possession by any such official in an involuntary case or other proceeding commenced against it, or shall make a general assignment for the benefit of creditors, or shall fail generally to pay, or shall admit in writing its inability to pay, its debts as they become due, or shall take any corporate action to authorize any of the foregoing; or

(ix) an involuntary case or other proceeding shall be commenced against the Company seeking liquidation, reorganization or other relief with respect to it or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any substantial part of its property, and such involuntary case or other proceeding shall remain undismissed and unstayed for a period of 60 days; or an order for relief shall be entered against the Company under the Bankruptcy Code; or

(x) any member of the ERISA Group shall fail to pay when due an amount or amounts aggregating in excess of $50,000,000 which it shall have become liable to pay under Title IV of ERISA; or notice of intent to terminate a Material Plan shall be filed under Title IV of

ERISA by any member of the ERISA Group, any plan administrator or any combination of the foregoing; or the PBGC shall institute proceedings under Title IV of ERISA to terminate, to impose liability (other than for premiums under Section 4007 of ERISA) in respect of, or to cause a trustee to be appointed to administer any Material Plan; or a condition shall exist by reason of which the PBGC would be entitled to obtain a decree adjudicating that any Material Plan must be terminated; or there shall occur a complete or partial withdrawal from, or default, within the meaning of Section 4219(c)(5) of ERISA, with respect to, one or more Multiemployer Plans which could reasonably be expected to cause one or more members of the ERISA Group to incur a current payment obligation in excess of $50,000,000; or

(xi) the Company shall fail within sixty (60) days to pay, bond or otherwise discharge any judgment or order for the payment of money in excess of $20,000,000, entered against the Company that is not stayed on appeal or otherwise being appropriately contested in good faith; or

(xii) a Change of Control shall have occurred;

For purposes of the foregoing:

"Change of Control" means (i) the acquisition by any person, or two or more persons acting in concert, of beneficial ownership (within the meaning of Rule 13d-3 of the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended) of 25% or more of the outstanding shares of voting stock of PPL Corporation or its successors or (ii) the failure at any time of PPL Corporation or its successors to own 80% or more of the outstanding shares of the voting stock in the Company.

"Material Debt" means debt (other than debt under the Loan Documents) of the Company in a principal or face amount exceeding $50,000,000

Appendix C of the Reoffering Circular is hereby amended to read in its entirety as follows:

Sumitomo Mitsui Banking Corporation, New York Branch

The information under this heading has been provided solely by Sumitomo Mitsui Banking Corporation, New York Branch and is believed to be reliable. This information has not been verified independently by the Company, the Issuer or the Remarketing Agent. The Company, the Issuer and the Remarketing Agent make no representation whatsoever as to the accuracy, adequacy or completeness of such information.

Sumitomo Mitsui Banking Corporation

Sumitomo Mitsui Banking Corporation (*Kabushiki Kaisha Mitsui Sumitomo Ginko*) ("SMBC") is a joint stock corporation with limited liability (*Kabushiki Kaisha*) under the laws of Japan. The registered head office of SMBC is located at 1-2, Yurakucho 1-chome, Chiyoda-ku, Tokyo, Japan.

SMBC was established in April 2001 through the merger of two leading banks, The Sakura Bank, Limited and The Sumitomo Bank, Limited. In December 2002, Sumitomo Mitsui Financial Group, Inc. ("SMFG") was established through a stock transfer as a holding company under which SMBC became a wholly owned subsidiary. SMFG reported ¥ 123,159,513 million in consolidated total assets as of March 31, 2010.

SMBC is one of the world's leading commercial banks and provides an extensive range of banking services to its customers in Japan and overseas. In Japan, SMBC accepts deposits, makes loans and extends guarantees to corporations, individuals, governments and governmental entities. It also offers financing solutions such as syndicated lending, structured finance and project finance. SMBC also underwrites and deals in bonds issued by or under the guarantee of the Japanese government and local government authorities, and acts in various administrative and advisory capacities for certain types of corporate and government bonds. Internationally, SMBC operates through a network of branches, representative offices, subsidiaries and affiliates to provide many financing products including syndicated lending and project finance.

The New York Branch of SMBC is licensed by the State of New York Banking Department to conduct branch banking business at 277 Park Avenue, New York, New York, and is subject to examination by the State of New York Banking Department and the Federal Reserve Bank of New York.

Financial and Other Information

Audited consolidated financial statements for SMFG and its consolidated subsidiaries for the fiscal years ended March 31, 2010, as well as certain unaudited financial information for SMFG and SMBC for the fiscal period ended through December 31, 2010, as well as other corporate data, financial information and analyses are available in English on the website of the Parent at www.smfg.co.jp/english.

The information herein has been obtained from SMBC, which is solely responsible for its content. The delivery of the Reoffering Circular shall not create any implication that there has been no change in the affairs of SMBC since the date hereof, or that the information contained or referred herein is correct as of any time subsequent to its date.

Appendix A of the Reoffering Circular is hereby amended to read in its entirety as follows:

Appendix A

Kentucky Utilities Company –

Financial Statements and Additional Information

This Appendix A includes a description of the Business of Kentucky Utilities Company ("KU"), certain risk factors associated with KU, Selected Financial Information, Management's Discussion and Analysis, and the Consolidated Financial Statements as of December 31, 2010 and 2009 and for the Years Ended December 31, 2010, 2009, and 2008 (Audited).

The information contained in this Appendix A relates to and has been obtained from KU and from other sources as shown herein. The delivery of this Supplement shall not create any implication that there has been no change in the affairs of KU since the date hereof, or that the information contained or incorporated by reference in this Appendix A is correct at any time subsequent to its date. In this Appendix A, "KU", "the Company", "we", "us" or "our" refer to Kentucky Utilities Company.

Summary

Kentucky Utilities Company

Kentucky Utilities Company, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 514,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and to less than 10 customers in Tennessee. Our service area covers approximately 6,600 noncontiguous square miles. Approximately 98% of the electricity generated by us is produced by our coal-fired electric generating stations. The remainder is generated by natural gas and oil fueled combustion turbines and a hydroelectric power plant. In Virginia, we operate under the name Old Dominion Power Company. We also sell wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of LG&E and KU Energy LLC. On November 1, 2010, PPL Corporation purchased all of the interests of LG&E and KU Energy LLC and, indirectly, all of the stock of the Company from E.ON AG, making KU an indirect wholly-owned subsidiary of PPL Corporation. KU's affiliate, Louisville Gas and Electric Company ("LG&E"), is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and natural gas in Kentucky.

Kentucky Utilities Company

Financial Statements and Additional Information

As of December 31, 2010 and 2009 and

for the years ended December 31, 2010, 2009 and 2008

Index of Abbreviations

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Company	Kentucky Utilities Company
CT	Combustion Turbine
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Electric Energy, Inc.
EKPC	East Kentucky Power Cooperative, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC and Subsidiaries
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
Fidelia	Fidelia Corporation (an E.ON affiliate)
GAAP	U.S. Generally Accepted Accounting Principles
GAC	Group Annuity Contract
GHG	Greenhouse Gas
Gwh	Gigawatt hours or one thousand Mwh
IBEW	International Brotherhood of Electrical Workers
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
IRS	Internal Revenue Service
KCCS	Kentucky Consortium for Carbon Storage
KDAQ	Kentucky Division for Air Quality
Kentucky Commission	Kentucky Public Service Commission
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
kWh	Kilowatt hours
LG&E	Louisville Gas and Electric Company
LIBOR	London Interbank Offered Rate
LKE	LG&E and KU Energy LLC and Subsidiaries (formerly E.ON U.S. LLC and Subsidiaries)
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units

Index of Abbreviations

Moody's	Moody's Investor Services, Inc.
MVA	Megavolt-ampere
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NO_2	Nitrogen Dioxide
NOV	Notice of Violation
NOx	Nitrogen Oxide
OATT	Open Access Transmission Tariff
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation
PPL	PPL Corporation
Predecessor	The Company during the time period prior to November 1, 2010
PUHCA 2005	Public Utility Holding Company Act of 2005
RSG	Revenue Sufficiency Guarantee
S&P	Standard & Poor's Rating Service
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
Servco	LG&E and KU Services Company (formerly E.ON U.S. Services Inc.)
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool, Inc
Successor	The Company during the time period after October 31, 2010
TC1	Trimble County Unit 1
TC2	Trimble County Unit 2
TVA	Tennessee Valley Authority
Utilities	KU and LG&E
VDT	Value Delivery Team Process
Virginia Commission	Virginia State Corporation Commission

Table of Contents

Forward-Looking Information

KU uses forward-looking statements in this annual report. Statements that are not historical facts are forward-looking statements, and are based on beliefs and assumptions of management, and on information currently available to management. Forward-looking statements include statements preceded by, followed by or using such words as “believe,” “expect,” “anticipate,” “plan,” “estimate” or similar expressions. Such statements speak only as of the date they are made, and the Company undertakes no obligation to update publicly any of them in light of new information or future events. Actual results may materially differ from those implied by forward-looking statements due to known and unknown risks and uncertainties. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- fuel supply availability;
- weather conditions affecting generation production, customer energy use and operating costs;
- operation, availability and operating costs of existing generation facilities;
- transmission and distribution system conditions and operating costs;
- collective labor bargaining negotiations;
- the outcome of litigation against the Company;
- potential effects of threatened or actual terrorism or war or other hostilities;
- commitments and liabilities;
- market demand and prices for energy, capacity, transmission services, emission allowances and delivered fuel;
- competition in retail and wholesale power markets;
- liquidity of wholesale power markets;
- defaults by counterparties under the Company’s energy, fuel or other power product contracts;
- market prices of commodity inputs for ongoing capital expenditures;
- capital market conditions, including the availability of capital or credit, changes in interest rates, and decisions regarding capital structure;
- the fair value of debt and equity securities and the impact on defined benefit costs and resultant cash funding requirements for defined benefit plans;
- interest rates and their effect on pension and retiree medical liabilities;
- volatility in or the impact of other changes in financial or commodity markets and economic conditions;
- profitability and liquidity, including access to capital markets and credit facilities;
- new accounting requirements or new interpretations or applications of existing requirements;
- securities and credit ratings;
- current and future environmental conditions and requirements and the related costs of compliance, including environmental capital expenditures, emission allowance costs and other expenses;
- political, regulatory or economic conditions in states, regions or countries where the Company conducts business;
- receipt of necessary governmental permits, approvals and rate relief;
- new state or federal legislation, including new tax, environmental, health care or pension-related legislation;
- state or federal regulatory developments;
- the impact of any state or federal investigations applicable to the Company and the energy industry;
- the effect of any business or industry restructuring;
- development of new projects, markets and technologies;

- performance of new ventures; and
- asset acquisitions and dispositions.

In light of these risks and uncertainties, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than the Company has described. For additional details regarding these and other risks and uncertainties, see Risk Factors.

Business

General

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 514,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in five counties in southwestern Virginia and less than ten customers in Tennessee. KU's service area covers approximately 6,600 noncontiguous square miles. Approximately 98% of the electricity generated by KU is produced by its coal-fired electric generating stations. The remainder is generated by natural gas and oil fueled CTs and a hydroelectric power plant. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

On November 1, 2010, KU became an indirect wholly owned subsidiary of PPL, when PPL acquired all of the outstanding limited liability company interests in the Company's direct parent, LKE, from E.ON US Investments Corp. LKE, a Kentucky limited liability company, also owns the affiliate, LG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy and distribution and sale of natural gas in Kentucky. Following the acquisition, the Company's business has not changed. KU and LG&E are continuing as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies.

Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K.

Predecessor and Successor

KU's historical financial results are presented using "Predecessor" or "Successor" to designate the periods before or after PPL's acquisition of LKE. Predecessor covers the time period prior to November 1, 2010. Successor covers the time period after October 31, 2010. Certain accounting and presentation methods were changed to acceptable alternatives to conform to PPL accounting policies and the cost basis of certain assets and liabilities were changed as of November 1, 2010, as a result of the application of push-down accounting. Consequently, the financial position, results of operations and cash flows for the Successor period are not comparable to the Predecessor period.

Despite the separate presentation, the core operations of the Company have not changed. See Note 1, Summary of Significant Accounting Policies, for the major differences in Predecessor and Successor accounting policies. See Note 2, Acquisition by PPL, for information regarding the acquisition and the purchase accounting adjustments.

Operations

Dollars are in millions unless otherwise noted.

The sources of operating revenues and volumes of sales for the following periods in 2010, 2009 and 2008 were as follows:

	Successor		Predecessor					
	November 1, 2010 through December 31, 2010		January 1, 2010 through October 31, 2010		Year Ended December 31, 2009		Year Ended December 31, 2008	
	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)
Residential	$ 106	1,394	$ 440	5,788	$ 480	6,594	$ 462	6,803
Industrial and commercial	117	1,876	588	9,152	637	10,171	636	10,709
Municipals	15	326	88	1,676	91	1,848	92	1,971
Other retail	20	273	114	1,453	118	1,647	108	1,707
Wholesale	5	68	18	376	29	660	107	2,894
	$ 263	3,937	$ 1,248	18,445	$ 1,355	20,920	$ 1,405	24,084

KU's peak load in 2010 was 4,517 Mw on December 15, 2010, when the temperature dropped to a low of 3 degrees Fahrenheit in Lexington. KU's all time peak load was 4,640 Mw and occurred on January 16, 2009, when the temperature dropped to a low of -2 degrees Fahrenheit in Lexington.

The Company's power generating system includes coal-fired steam generating stations, with natural gas and oil fueled CTs which supplement the system during peak or emergency periods. As of December 31, 2010, KU's system capacity was:

Fuel/Plant	Total Summer Mw Capacity (a)	% Ownership	Ownership or Lease Interest in Mw	Location
Coal (steam)				
Ghent	1,918	100.00	1,918	Carroll County, KY
E.W. Brown	684	100.00	684	Mercer County, KY
Green River	163	100.00	163	Muhlenberg County, KY
Tyrone	71	100.00	71	Woodford County, KY
OVEC - Clifty Creek (b)	1,304	2.50	33	Jefferson County, IN
OVEC - Kyger Creek (b)	1,086	2.50	27	Gallia County, OH
Total steam	5,226		2,896	
Natural gas/oil (combustion turbines)				
E.W. Brown Units 8-11	480	100.00	480	Mercer County, KY
Trimble County Units 7-10 (c)	640	63.00	403	Trimble County, KY
Trimble County Units 5-6 (c)	320	71.00	227	Trimble County, KY
E.W. Brown Units 6-7 (c)	338	62.00	214	Mercer County, KY
Paddy's Run (c)	158	47.00	74	Jefferson County, KY
E.W. Brown Unit 5	129	47.00	63	Mercer County, KY
Haefling	36	100.00	36	Fayette County, KY
Total combustion turbines	2,101		1,497	

Fuel/Plant	Total Summer Mw Capacity (a)	% Ownership	Ownership or Lease Interest in Mw	Location
Hydro				
Dix Dam Hydroelectric Station	24	100.00	24	Mercer County, KY
Total hydro	24		24	
Total system capacity	7,351		4,417	

(a) The capacity of generation units is based on a number of factors, including the operating experience and physical conditions of the units and may be revised periodically to reflect changed circumstances.
(b) KU is contractually entitled to 2.50% of OVEC's output based on a power purchase agreement which is comprised of annual minimum debt service payments, as well as contractually-required reimbursement of plant operating, maintenance and other expenses. OVEC's capacity is shown at unit nameplate ratings.
(c) Units are jointly owned with LG&E. See Note 14, Jointly Owned Electric Utility Plant, for further information.

With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. Unit 2 is coal-fired and has a capacity of 760 Mw, of which KU's share is 462 Mw.

On December 31, 2010, KU's transmission system included 132 substations (54 of which are shared with the distribution system) with transformer capacity of approximately 13,136 MVA and approximately 4,076 miles of lines. The distribution system included 480 substations (54 of which are shared with the transmission system) with transformer capacity of approximately 7,044 MVA, and approximately 14,123 miles of overhead lines and 2,221 miles of underground conduit.

KU had a power supply contract with OMU that was terminated by OMU in May 2010. KU owns 20% of EEI's common stock and 2.5% of OVEC's common stock. KU has power purchase rights for its portion of OVEC's output. Additional information regarding this relationship is provided in Note 1, Summary of Significant Accounting Policies and Note 13, Commitments and Contingencies.

KU contracts with the TVA to act as KU's transmission reliability coordinator and SPP to function as KU's independent transmission operator, pursuant to FERC requirements. The TVA and SPP contracts provide services through August 31, 2011 and August 31, 2012, respectively. See Note 3, Rates and Regulatory Matters, for further information.

KU and LG&E jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has

excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are recorded as intercompany wholesale sales and purchases and are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the Utilities. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

Substantially all of KU's real and tangible property located in Kentucky is subject to a mortgage lien, securing its first mortgage bonds. See Note 11, Long-Term Debt, for further information.

Rates and Regulations

PPL, KU's ultimate parent, is a holding company under PUHCA 2005. PPL, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries are subject to extensive regulation by the FERC with respect to numerous matters, including: electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. KU believes that it has adequate authority (including financing authority) under existing FERC Orders and regulations to conduct its business and will seek additional authorization when necessary.

The Company is subject to the jurisdiction of the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority in virtually all matters related to electric utility regulation, and as such, its accounting is subject to the regulated operations guidance of the FASB ASC. Given its competitive position in the marketplace and the status of regulation in Kentucky, Virginia and Tennessee there are no plans or intentions to discontinue the application of the regulated operations guidance of the FASB ASC.

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments Corp., PPL and E.ON.

The transaction was subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including the FERC and state regulators in Kentucky, Virginia and Tennessee) and the absence of injunctions or restraints imposed by governmental entities.

Change of control and financing-related applications were filed on May 28, 2010, with the Kentucky Commission and on June 15, 2010, with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings and data request filings and responses occurred. Early termination of the Hart-Scott-Rodino waiting period was received on August 2, 2010.

A hearing in the Kentucky Commission proceedings was held on September 8, 2010, at which time a unanimous settlement agreement was presented. In the settlement, KU committed that no base rate increases would take effect before January 1, 2013. The KU rate increases that took effect on August 1,

2010, were not impacted by the settlement. Under the terms of the settlement, KU retains the right to seek approval for the deferral of "extraordinary and uncontrollable costs." Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and demand-side management cost trackers. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Company file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits KU to earn up to a 10.75% return on equity. Any earnings above a 10.75% return on equity will be shared with customers on a 50%/50% basis. On September 30, 2010, the Kentucky Commission issued an Order approving the transfer of ownership of KU via the acquisition of E.ON U.S. by PPL, incorporating the terms of the submitted settlement. On October 19, 2010 and October 21, 2010, respectively, Orders approving the acquisition of E.ON U.S. by PPL were received from the Virginia Commission and the Tennessee Regulatory Authority. The Commissions' Orders contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In mid-September 2010, KU and other applicants in the FERC change of control proceeding reached an agreement with the protesters, whereby such protests have been withdrawn. The agreement, which was filed for consideration with the FERC, includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an agreement not to terminate certain KU municipal customer contracts prior to January 2017, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that KU agreed not to seek the same transaction-related cost from retail customers and agreements to coordinate with protesters in certain open or ongoing matters. A FERC Order approving the transaction was received on October 26, 2010, and the transaction was completed on November 1, 2010.

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $135 million annually. In June 2010, KU and all of the intervenors, except the AG, agreed to a stipulation providing for an increase in electric base rates of $98 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulation, including a return on equity range of 9.75-10.75%. The new rates became effective on August 1, 2010.

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based on a return on equity of 12%. As permitted, pursuant to a Virginia Commission Order, KU elected to implement the proposed rates effective November 1, 2009, on an interim basis. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing a base rate revenue increase of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU refunded approximately $1 million in interim rate amounts in excess of the ultimate approved rates.

In January 2009, a significant ice storm passed through KU's service area causing approximately 199,000 customer outages, followed closely by a severe wind storm in February 2009 causing approximately 44,000 customer outages. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future

recovery approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $62 million based on its actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, the Company established a regulatory asset of $57 million for actual costs incurred. KU received approval in its 2010 base rate case to recover this asset over a ten year period with recovery beginning August 1, 2010.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service area causing significant outages and system damage. In October 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset and defer for future recovery approximately $3 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $3 million based on its actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, the Company established a regulatory asset of $2 million for actual costs incurred. The Company received approval in its 2010 base rate case to recover this asset over a ten year period beginning August 1, 2010.

In September 2008, KU filed an application with the FERC for increases in electric base rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from an all-in stated unit charge rates to an unbundled formula rate, including an annual adjustment mechanism. In May 2009, the FERC issued an Order approving a settlement among the parties in the case, incorporating increases of approximately 3% from prior rates and a return on equity of 11%. In May 2010, KU submitted to the FERC the proposed current annual adjustments to the formula rates, which incorporated certain proposed increases. Updated rates, including certain further adjustments from a review process involving wholesale requirements customers, became effective as of July 1, 2010.

By mutual agreement, the parties' settlement of the 2008 application left outstanding the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. An Order was issued by the FERC in July 2010, indicating that KU is not required to allocate a portion of any renewable resources to the twelve municipalities, thus resolving the remaining issue.

In July 2008, KU filed an application with the Kentucky Commission requesting an increase in electric base rates. In January 2009, KU, the AG, the KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which KU's electric base rates decreased by $9 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009.

For a further discussion of regulatory matters, see Note 3, Rates and Regulatory Matters.

Coal Supply

Coal-fired generating units provided approximately 98% of KU's net kWh generation for 2010. The remaining net generation was provided by natural gas and oil fueled CTs and a hydroelectric plant. Coal is expected to be the predominant fuel used by KU in the foreseeable future, with natural gas and oil

being used for peaking capacity and flame stabilization in coal-fired boilers or in emergencies. The Company has no nuclear generating units and has no plans to build any in the foreseeable future.

Fuel inventory is maintained at levels estimated to be necessary to avoid operational disruptions at the coal-fired generating units. Reliability of coal deliveries can be affected periodically by a number of factors including fluctuations in demand, coal mine production issues and other supplier or transporter operating difficulties.

KU has entered into coal supply agreements with various suppliers for coal deliveries for 2011 and beyond and normally augments its coal supply agreements with spot market purchases. The Company has a coal inventory policy which it believes provides adequate protection under most contingencies.

KU expects to continue purchasing most of its coal, which has sulfur content in the 0.7% - 3.5% range, from western and eastern Kentucky, West Virginia, southern Indiana, southern Illinois, Ohio and Wyoming for the foreseeable future. This supply, in combination with the installation of FGDs (SO_2 removal systems), KU expects its use of higher sulfur coal to increase, the combination of which is expected to enable KU to continue to provide electric service in compliance with existing environmental laws and regulations. Coal is delivered to KU’s generating stations by a mix of transportation modes, including barge, truck and rail.

Seasonality

Demand for and market prices for electricity are affected by weather. As a result, KU’s overall operating results in the future may fluctuate substantially on a seasonal basis, especially when more severe weather conditions such as heat waves or winter storms make such fluctuations more pronounced. The pattern of this fluctuation may change depending on the type and location of the facilities KU owns and the terms of its contracts to purchase or sell electricity.

Environmental Matters

General

Protection of the environment is a major priority for KU and a significant element of its business activities. KU’s properties and operations are subject to extensive environmental-related oversight by federal, state and local regulatory agencies, including via air quality, water quality, waste management and similar laws and regulations. Therefore, KU must conduct its operations in accordance with numerous permit and other requirements issued under or contained in such laws or regulations.

Climate Change

Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation’s Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3% by 2012, 17% by 2020 and 83% by 2050. Similar legislation has been considered in the U.S. Senate, but the prospects for

passage remain uncertain. In late 2009, the EPA issued a final endangerment finding relating to mobile sources of GHGs and a GHG reporting requirement beginning in 2010. In 2010, the EPA issued a final rule requiring implementation of best available control technology for GHG emissions from new or modified power plants, effective January 2011. In December 2010, the EPA announced that it intends to propose New Source Performance Standards addressing GHG emissions from new and existing power plants, with a proposed rule expected in July 2011. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, KU, as a primarily coal-fired utility, could be highly affected by such proceedings.

Among other emissions, GHGs include carbon-dioxide, which is produced via the combustion of fossil fuels such as coal and natural gas. KU's generating fleet is approximately 66% coal-fired, 34% oil/natural gas-fired and less than 1% hydroelectric based on capacity. During 2010, KU produced approximately 98% of its electricity from coal, 2% from natural gas combustion and less than 1% from hydroelectric generation, based on Mwh. During 2010, KU's emissions of GHGs were approximately 16.4 million metric tons of carbon-dioxide equivalents from KU's owned or controlled generation sources. While its generation activities account for the bulk of its GHG emissions, other GHG sources at KU include operation of motor vehicles and powered equipment, leakage or evaporation associated with natural gas pipelines, refrigerating equipment and similar activities.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. Based on prior regulatory precedent, KU currently anticipates that many of such direct costs may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, but the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change and other environmental matters will likely increase the level of capital expenditures and operating and maintenance costs incurred by the Company during the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. In order to comply with the coal combustion residual rules and the above referenced air rules, capital expenditures for KU are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary. This estimate does not include compliance with GHG rules or contemplated water-related environmental changes. See Risk Factors, Management's Discussion and Analysis and Note 13, Commitments and Contingencies, for further information.

State Executive or Legislative Matters

In November 2008, the Commonwealth of Kentucky issued an action plan to create efficient, sustainable energy solutions and strategies and move toward state energy independence. The plan outlines the following seven strategies to work toward these goals:

- Improve the energy efficiency of Kentucky’s homes, buildings, industries and transportation fleet
- Increase Kentucky’s use of renewable energy
- Sustainably grow Kentucky’s production of biofuels
- Develop a coal-to-liquids industry in Kentucky to replace petroleum-based liquids
- Implement a major and comprehensive effort to increase natural gas supplies, including coal-to-natural gas in Kentucky
- Initiate aggressive carbon capture/sequestration projects for coal-generated electricity in Kentucky
- Examine the use of nuclear power for electricity generation in Kentucky

In December 2009, the Governor of Kentucky’s Executive Task Force on Biomass and Biofuels issued a final report to establish potential strategic actions to develop biomass and biofuels industries in Kentucky. The plan noted the potential importance of biomass as a renewable energy source available to Kentucky and discussed various goals or mechanisms, such as the use of approximately 25 million tons of biomass for generation fuel annually, allotment of electricity and natural gas taxes and state tax credits to support biomass development.

In January 2010, a state-established Kentucky Climate Action Plan Council (the “Council”) commenced formal activities. The Council, which includes governmental, industry, consumer and other representatives, seeks to identify possible Kentucky responses to potential climate change and federal legislation, including increasing statewide energy efficiency, energy independence and economic growth. The Council has established various technical work groups, including in the areas of energy supply and energy efficiency/conservation, to provide input, data and recommendations.

During the current session of the Kentucky General Assembly, as during prior legislative sessions, legislators have introduced or are expected to introduce various bills with respect to environmental or utility matters, including potential requirements relating to renewable energy portfolios, energy conservation measures, coal mining or coal byproduct operations and other matters. The current session is scheduled to end in March 2011 and until such time the prospects and final terms of any such legislation cannot be determined. Legislative and regulatory actions as a result of these proposals and their impact on KU, which may be significant, cannot currently be predicted.

Franchises and Licenses

KU provides electric delivery service in its various service areas pursuant to certain franchises, licenses, statutory service areas, easements and other rights or permissions granted by state legislatures, cities or municipalities or other entities.

Competition

There are currently no other electric utilities operating within the electric service areas of KU. Neither the Kentucky General Assembly nor the Kentucky Commission has adopted or approved a plan or timetable for retail electric industry competition in Kentucky. The nature or timing of any legislative or regulatory actions regarding industry restructuring and their impact on KU, which may be significant, cannot currently be predicted. Virginia, formerly a competitive jurisdiction, has enacted legislation which implements a hybrid model of cost-based regulation. See Note 3, Rates and Regulatory Matters, for further information.

Employees and Labor Relations

KU had 974 employees at December 31, 2010, consisting of 973 full-time employees and 1 part-time employee. Of the total employees, 145, or 15%, were operating, maintenance and construction employees represented by the IBEW Local 2100 and the United Steelworkers of America ("USWA") Local 9447-01. In August 2009, the Company and its employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement that provides for negotiated increases or changes to wages, benefits or other provisions and annual wage re-openers. In August 2008, the Company and its employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement that provides for negotiated increases or changes to wages, benefits or other provisions and annual wage re-openers.

Officers of the Company

Officers are elected annually by the Board of Directors. There are no family relationships among any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

Except as may be set forth in Legal Proceedings, there have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

Listed below are the executive officers at December 31, 2010.

Name	Age	Positions Held During the Past Five Years	Dates
Victor A. Staffieri	55	Chairman of the Board, President and Chief Executive Officer	May 2001 – present
John R. McCall	67	Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer	July 1994 – present
Chris Hermann	63	Senior Vice President – Energy Delivery	February 2003 – present
Paula H. Pottinger	53	Senior Vice President – Human Resources	January 2006 – present
S. Bradford Rives	52	Chief Financial Officer	September 2003 – present
Paul W. Thompson	53	Senior Vice President – Energy Services	June 2000 – present

Officers generally serve in the same capacities at the Company, LKE and LG&E.

Risk Factors

Any of the events or circumstances described as risks below could result in a significant or material adverse effect on the business, results of operations, cash flows or financial condition. The risks and uncertainties described below may not be the only risks and uncertainties that KU faces. Additional risks and uncertainties not currently known or that KU currently deems immaterial may also result in a significant or material adverse effect on the business, results of operations, cash flow or financial condition.

KU's business is subject to significant and complex governmental regulation.

Various federal and state entities, including but not limited to the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority, regulate many aspects of utility operations of KU, including the following:

- the rates that KU may charge and the terms and conditions of the Company's service and operations;
- financial and capital structure matters;
- siting and construction of facilities;
- mandatory reliability and safety standards and other standards of conduct;
- accounting, depreciation and cost allocation methodologies;
- tax matters;
- affiliate restrictions;
- acquisition and disposal of utility assets and securities; and
- various other matters.

Such regulations or changes thereto may subject KU to higher operating costs or increased capital expenditures and failure to comply could result in sanctions or possible penalties. In any rate-setting proceedings, federal or state agencies, intervenors and other permitted parties may challenge rate requests and ultimately reduce, alter or limit the rates the Company seeks.

The profitability of KU is highly dependent on its ability to recover the costs of providing energy and utility services to its customers and earn an adequate return on its capital investments. KU currently provides services to retail customers at rates approved by one or more federal or state regulatory commissions, including those commissions referred to above. While these rates are generally regulated based on an analysis of their costs incurred in a base year, the rates KU is allowed to charge may or may not match its costs at any given time. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commissions will consider all of the costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of KU's costs or an adequate return on KU's capital investments. If the Company's costs are not adequately recovered through rates, it could have an adverse affect on the business, results of operations, cash flows or financial condition.

As part of the PPL acquisition commitments, KU has agreed, subject to certain limited exceptions such as fuel and environmental cost recoveries, that no base rate increase would take effect for Kentucky retail customers before January 1, 2013.

Transmission and interstate market activities of KU, as well as other aspects of the business, are subject to significant FERC regulation.

KU is subject to extensive regulation by the FERC covering matters including rates charged to transmission users, market-based or cost-based rates applicable to wholesale customers; interstate power market structure; construction and operation of transmission facilities; mandatory reliability standards; standards of conduct and affiliate restrictions and other matters. Existing FERC regulation, changes thereto or issuances of new rules or situations of non-compliance, including but not limited to the areas of market-based tariff authority, RSG resettlements in the MISO market, mandatory reliability standards and natural gas transportation regulation can affect the earnings, operations or other activities of KU.

Changes in transmission and wholesale power market structures could increase costs or reduce revenues.

Wholesale sales fluctuate with regional demand, fuel prices and contracted capacity. Changes to transmission and wholesale power market structures and prices may occur in the future, are not estimable and may result in unforeseen effects on energy purchases and sales, transmission and related costs or revenues. These can include commercial or regulatory changes affecting power pools, exchanges or markets in which KU participates.

KU undertakes significant capital projects and these activities are subject to unforeseen costs, delays or failures, as well as risk of inadequate recovery of resulting costs.

KU's business is capital intensive and requires significant investments in energy generation and distribution and other infrastructure projects, such as projects for environmental compliance. The completion of these projects without delays or cost overruns is subject to risks in many areas, including the following:

- approval, licensing and permitting;
- land acquisition and the availability of suitable land;
- skilled labor or equipment shortages;
- construction problems or delays, including disputes with third party intervenors; increases in commodity prices or labor rates;
- contractor performance;
- environmental considerations and regulations;
- weather and geological issues; and
- political, labor and regulatory developments.

Failure to complete capital projects on schedule or on budget, or at all, could adversely affect the Company's financial performance, operations and future growth.

The costs of compliance with, and liabilities under, environmental laws are significant and are subject to continual changes.

Extensive federal, state and local environmental laws and regulations are applicable to KU's air emissions, water discharges and the management of hazardous and solid waste, among other areas; and

the costs of compliance or alleged non-compliance cannot be predicted with certainty but could be material. In addition, KU's costs may increase significantly if the requirements or scope of environmental laws or regulations, or similar rules, are expanded or changed from prior versions by the relevant agencies. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions. Many of these environmental law considerations are also applicable to the operations of key suppliers, or customers, such as coal producers, industrial power users, etc., and may impact the costs of their products or their demand for KU's services.

KU is subject to operational and financial risks regarding certain on-going developments concerning environmental regulation.

A number of regulatory initiatives have been implemented or are under development which could have the effect of significantly increasing the environmental regulation or operational or compliance costs related to a number of emissions or operating activities which are associated with the combustion of coal as occurs at the Company's generating stations. Such developments could include potential new or revised federal or state legislation or regulation regarding emissions of NOx, SO_2, mercury and other particulates generally and regarding storage of coal combustion byproducts. Additional regulatory initiatives may occur in other areas involving the Company's operations, including revision of limitations on water discharge or intake activities or increased standards relating to polychlorinated biphenyl usage. Compliance with any new laws or regulations in these matters could result in significant changes to KU's operations, significant capital expenditures by the Company or significant increases in the cost of conducting business.

Operating results are affected by weather conditions, including storms and seasonal temperature variations, as well as by significant man-made or accidental disturbances, including terrorism or natural disasters.

These weather or other factors can significantly affect the finances or operations of KU by changing demand levels; causing outages; damaging infrastructure or requiring significant repair costs; affecting capital markets and general economic conditions or impacting future growth.

KU is subject to operational and financial risks regarding potential developments concerning global climate change.

Various regulatory and industry initiatives have been implemented or are under development to regulate or otherwise reduce emissions of GHGs, which are emitted from the combustion of fossil fuels such as coal and natural gas, as occurs at the Company's generating stations. Such developments could include potential federal or state legislation or industry initiatives allocating or limiting GHG emissions; establishing costs or charges on GHG emissions or on fuels relating to such emissions; requiring GHG capture and sequestration; establishing renewable portfolio standards or generation fleet-diversification requirements to address GHG emissions; promoting energy efficiency and conservation; changes in transmission grid construction, operation or pricing to accommodate GHG-related initiatives; or other measures. The generation fleet of KU is predominantly coal-fired and may be highly impacted by developments in this area. Compliance with any new laws or regulations regarding the reduction of GHG emissions could result in significant changes to KU's operations, significant capital expenditures by the Company and a significant increase in the cost of conducting business. KU may face strong

competition for, or difficulty in obtaining, required GHG-compliance related goods and services, including construction services, emissions allowances and financing, insurance and other inputs relating thereto. Increases in KU's costs or prices of producing or selling electric power due to GHG-related developments could materially reduce or otherwise affect the demand, revenue or margin levels applicable to its power, thus adversely affecting its financial condition or results of operations.

KU is subject to physical, market and economic risks relating to potential effects of climate change.

Climate change may produce changes in weather or other environmental conditions, including temperature or precipitation changes, such as warming or drought. These changes may affect farm and agriculturally-dependent businesses and activities, which are an important part of Kentucky's economy, and thus may impact consumer demand for electric power. Temperature increases could result in increased overall electricity volumes or peaks and precipitation changes could result in altered availability of water for plant cooling operations. These or other meteorological changes could lead to increased operating costs, capital expenses or power purchase costs by KU. Conversely, climate change could have a number of potential impacts tending to reduce demand. Changes may entail more frequent or more intense storm activity, which, if severe, could temporarily disrupt regional economic conditions and adversely affect electricity demand levels. As discussed in other risk factors, storm outages and damage often directly decrease revenues or increase expenses, due to reduced usage and higher restoration charges, respectively. GHG regulation could increase the cost of electric power, particularly power generated by fossil fuels, and such increases could have a depressive effect on the regional economy. Reduced economic and consumer activity in the service area of KU, both in general and specific to certain industries and consumers accustomed to previously low-cost power, could reduce demand for KU's electricity. Also, demand for services could be similarly lowered should consumers' preferences or market factors move toward favoring energy efficiency, low-carbon power sources or reduced electric usage generally.

The business of KU is subject to risks associated with local, national and worldwide economic conditions.

The consequences of prolonged recessionary conditions may include a lower level of economic activity and uncertainty or volatility regarding energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption, unfavorable changes in energy and commodity prices and slower customer growth, which may adversely affect KU's future revenues and growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and the ability to raise capital. A deterioration of economic conditions may lead to decreased production by KU's industrial customers and, therefore, lower consumption of electricity. Decreased economic activity may also lead to fewer commercial and industrial customers and increased unemployment, which may in turn impact residential customers' ability to pay. Further, worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure. Changes in global demand may impact the ability to acquire sufficient supplies and the cost of those commodities may be higher than expected.

KU's business is concentrated in the Midwest United States, specifically Kentucky and Virginia.

Although the business of KU is concentrated in Kentucky and Virginia, it also operates in Tennessee. Local and regional economic conditions, such as population growth, industrial growth, expansion and economic development or employment levels, as well as the operational or financial performance of major industries or customers, can affect the demand for energy and KU's results of operations. Significant industries and activities in the service area of KU include aluminum and steel smelting and fabrication; chemical processing; coal, mineral and ceramic related activities; educational institutions; health care facilities; paper and pulp processing; metal fabrication; and water and sewer utilities. Any significant downturn in these industries or activities or in local and regional economic conditions in KU's service area may adversely affect the demand for electricity in the service area.

KU is subject to operational risks relating to KU's generating plants, transmission facilities, distribution equipment, information technology systems and other assets and activities.

Operation of power plants, transmission and distribution facilities, information technology systems and other assets and activities subjects KU to many risks, including the breakdown or failure of equipment; accidents; security breaches, viruses or outages affecting information technology systems; labor disputes; obsolescence; delivery/transportation problems and disruptions of fuel supply and performance below expected levels. Occurrences of these events may impact the ability of KU to conduct its business efficiently or lead to increased costs, expenses or losses.

Although KU maintains customary insurance coverage for certain of these risks common to utilities, it does not have insurance covering the transmission and distribution systems, other than substations, because it has found the cost of such insurance to be prohibitive. If KU is unable to recover the costs incurred in restoring transmission and distribution properties following damage resulting from ice storms, tornados or other natural disasters or to recover the costs of other liabilities arising from the risks of its business, through a change in rates or otherwise, or if such recovery is not received on a timely basis, it may not be able to restore losses or damages to its properties without an adverse effect on its financial condition, results of operations or its reputation.

KU is subject to liability risks relating to its generation, transmission, distribution and retail businesses.

The conduct of the physical and commercial operations of KU subjects it to many risks, including risks of potential physical injury, property damage or other financial affects, caused to or caused by employees, customers, contractors, vendors, contractual or financial counterparties and other third parties.

KU could be negatively affected by rising interest rates, downgrades to bond credit ratings or other negative developments in its ability to access capital markets.

In the ordinary course of business, KU is reliant upon adequate long-term and short-term financing means to fund significant capital expenditures, debt interest or maturities and operating needs. As a capital-intensive business, the Company is sensitive to developments in interest rate levels; credit rating considerations; insurance, security or collateral requirements; market liquidity and credit availability and

refinancing steps necessary or advisable to respond to credit market changes. Changes in these conditions could result in increased costs and decreased liquidity available to the Company.

KU is subject to commodity price risk, credit risk, counterparty risk and other risks associated with the energy business.

General market or pricing developments or failures by counterparties to perform their obligations relating to energy, fuels, other commodities, goods, services or payments could result in potential increased costs to the Company.

KU is subject to risks associated with defined benefit retirement plans, health care plans, wages and other employee-related matters.

KU sponsors pension and postretirement benefit plans for its employees. Risks with respect to these plans include adverse developments in legislation or regulation, future costs or funding levels, returns on investments, market fluctuations, interest rates and actuarial matters. Changes in health care rules, market practices or cost structures can affect current or future funding requirements or liabilities. Without sustained growth in respective investments over time to increase the value of plan assets, KU could be required to fund plans with significant amounts of cash. KU is also subject to risks related to changing wage levels, whether related to collective bargaining agreements or employment market conditions, ability to attract and retain key personnel and changing costs of providing health care benefits.

KU is subject to risks associated with federal and state tax regulations.

Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact results of operations. KU is required to make judgments in order to estimate its obligations to taxing authorities. These tax obligations include income, property, sales and use and employment-related taxes. KU also estimates its ability to utilize tax benefits and tax credits. Due to the revenue needs of the states and jurisdictions in which KU operates, various tax and fee increases may be proposed or considered. KU cannot predict whether legislation or regulation will be introduced or the effect on the Company of any such changes. If enacted, any changes could increase tax expense and could have a negative impact on its results of operations and cash flows.

Legal Proceedings

Rates and Regulatory Matters

For a discussion of current rates and regulatory matters, including recent electric base rate increase proceedings, rate commitments in change-of-control proceedings, TC2 proceedings, FERC, Kentucky Commission and Virginia Commission proceedings and other rates or regulatory matters affecting KU, see Note 3, Rates and Regulatory Matters, and Note 13, Commitments and Contingencies.

Environmental

For a discussion of environmental matters, including potential coal combustion byproduct or ash pond regulation; additional reductions in SO_2, NOx and other regulated emissions; NOVs and other emissions proceedings; environmental permit challenges; and other environmental items affecting KU, see Risk Factors, Note 3, Rates and Regulatory Matters, and Note 13, Commitments and Contingencies.

Climate Change

For a discussion of matters relating to potential climate change, GHG emission or global warming developments, including increased legislative and regulatory activity which could limit or increase costs applicable to fossil fuel generation sources, legal proceedings claiming damages relating to global warming, GHG reporting requirements and other matters, see Business, Risk Factors, Management's Discussion and Analysis and Note 13, Commitments and Contingencies.

Litigation

In connection with an administrative proceeding alleging a violation by a former Argentine affiliate under that country's 2002-2003 emergency currency exchange laws, claims are pending against the affiliate's then directors, including two individuals who are executive officers of the Company, in a specialized Argentine financial criminal court. Under applicable Argentine laws, directors of a local company may be liable for monetary penalties for a subject company's violations of the currency laws. The affiliate and the relevant executive officers believe their actions were in compliance with the relevant laws and have presented defenses in the administrative and criminal proceedings. LKE has standard indemnification arrangements with its executive officers. The former affiliate is now owned by a third party, which has agreed to indemnify LKE and the relevant executive officers.

For a discussion of litigation matters, see Note 13, Commitments and Contingencies.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against KU. To the extent that damages are assessed in any of these lawsuits, the Company believes that its insurance coverage is adequate. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits and claims will have a material adverse effect on KU's financial position or results of operations.

Selected Financial Data

Dollars are in millions unless otherwise noted.

	Successor	Predecessor				
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,			
			2009	2008	2007	2006
Operating revenues	$ 263	$ 1,248	$ 1,355	$ 1,405	$ 1,272	$ 1,210
Operating income	$ 65	$ 285	$ 269	$ 260	$ 267	$ 235
Net income	$ 35	$ 140	$ 133	$ 158	$ 167	$ 152
Total assets	$ 6,059	$ 5,145	$ 4,956	$ 4,518	$ 3,796	$ 3,148
Long-term debt obligations (including amounts due within one year)	$ 1,841	$ 1,682	$ 1,682	$ 1,532	$ 1,264	$ 843

Management's Discussion and Analysis and Notes to Financial Statements should be read in conjunction with the above information.

Management's Discussion and Analysis

Management's Discussion and Analysis should be read in conjunction with the Financial Statements and Notes for the years ended December 31, 2010, 2009 and 2008. Dollars are in millions unless otherwise noted.

The purpose of "Management's Discussion and Analysis" is to provide information about KU's performance in implementing its' strategies and managing risks and challenges. Specifically:

- "Overview" provides background regarding KU's business and identifies significant matters with which management is primarily concerned in evaluation of KU's financial condition and operating results.
- "Results of Operations" provides a description of KU's operating results in 2010, 2009 and 2008, including a review of earnings and a brief outlook for 2011.
- "Financial Condition" provides an analysis of KU's liquidity position and credit profile, including its sources of cash (including bank credit facilities and sources of operating cash flow) and uses of cash (including contractual obligations and capital expenditure requirements) and the key risks and uncertainties that impact KU's past and future liquidity position and financial condition. This subsection also includes a discussion of KU's current credit ratings.
- "Application of Critical Accounting Policies and Estimates" provides an overview of the accounting policies that are particularly important to the results of operations and financial condition of KU and that require its management to make significant estimates, assumptions and other judgments.

Overview

KU is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. See the Business section for a description of the business. The rates KU charges its customers requires approval of the appropriate regulatory government agency. See Note 3, Rates and Regulatory Matters, for information regarding rate cases, regulatory assets and liabilities and other regulatory matters.

KU and its affiliate, LG&E, are wholly owned subsidiaries of LKE, a Kentucky limited liability company. PPL acquired LKE on November 1, 2010. Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K. Following the acquisition, both KU and LG&E continue operating as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies. See Note 2, Acquisition by PPL, for further information regarding the acquisition.

In operating its business, the Company faces several risks including credit risks, liquidity risks, interest rate risks and commodity and price risks. For instance, the Company has credit risks from counterparties, customers and effects of its' own credit ratings. KU attempts to manage these risks through the adoption of financial and operational risk management programs that, among other things, are designed to monitor and reduce its' exposure to these risks. Identified within "Management's

Discussion and Analysis" of "Financial Condition" and "Results of Operations" are risks KU's management currently consider material; these risks are not the only risks faced by KU. Additional risks not presently known or currently deemed immaterial may also impair KU's business operations. See Risk Factors and Financial Condition - Risk Management for further discussion.

Predecessor and Successor Financial Presentation

KU's financial statements and related financial and operating data include the periods before or after PPL's acquisition of LKE on November 1, 2010, and are labeled as Predecessor or Successor. KU applied push-down accounting to account for the acquisition. For accounting purposes only, push-down accounting is considered to create a new entity due to new cost basis assigned to assets, liabilities and equity as of the acquisition date. Consequently, KU's results of operations and cash flows for the Predecessor and Successor periods in 2010 are shown separately, rather than combined, in its audited financial statements.

In the "Management's Discussion and Analysis" of "Results of Operations" and "Financial Condition", the Company has included disclosure of the combined Predecessor and Successor results of operations and cash flows. Such presentation is considered to be a non-GAAP disclosure. KU has included such disclosure because the Company believes it facilitates the comparison of 2010 operating and financial performance to 2009 and 2008, and because the core operations of the Company have not changed as a result of the acquisition.

Competition

See the Business section for information concerning competition.

Environmental Matters

General

Protection of the environment is a major priority for KU and a significant element of its business activities. Extensive federal, state and local environmental laws and regulations are applicable to KU's air emissions, water discharges and the management of hazardous and solid waste, among other areas; and the costs of compliance or alleged non-compliance cannot be predicted with certainty but could be material. In addition, costs may increase significantly if the requirements or scope of environmental laws or regulations, or similar rules, are expanded or changed from prior versions by the relevant agencies. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions. Many of these environmental law considerations are also applicable to the operations of key suppliers, or customers, such as coal producers, industrial power users, etc., and may impact the costs of their products or their demand for KU's services.

Climate Change

Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of

Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3% by 2012, 17% by 2020 and 83% by 2050. Similar legislation has been considered in the U.S. Senate, but the prospects for passage remain uncertain. In late 2009, the EPA issued a final endangerment finding relating to mobile sources of GHGs and a GHG reporting requirement beginning in 2010. In 2010, the EPA issued a final rule requiring implementation of best available control technology for GHG emissions from new or modified power plants, effective January 2011. In December 2010, the EPA announced that it intends to propose New Source Performance Standards addressing GHG emissions from new and existing power plants, with a proposed rule expected in July 2011. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, KU, primarily a coal-fired utility, could be highly affected by such proceedings.

Other Environmental Regulatory Initiatives

The EPA has proposed or announced that it intends to propose a number of additional environmental regulations that could substantially impact utilities with coal-fired generating assets. These regulatory initiatives include revisions to the ambient air quality standards for SO_2, NO_2, ozone and particulate matter 2.5 microns in size or less, rules aimed at mitigating the interstate transport of SO_2 and NOx, a program governing emissions of hazardous air pollutants from utility generating units, a program for the management of coal combustion residuals, revised effluent guidelines for utility generating facilities and standards for cooling water intake structures. Such requirements could potentially mandate upgrade of existing emission controls, installation of additional emission controls such as FGDs, SCRs, fabric filter bag houses, activated carbon injection, wet electrostatic precipitators, closure of ash ponds and retrofit of landfills, installation of cooling towers, deployment of new water treatment technologies and retirement of facilities that cannot be retrofitted on a cost effective basis.

The cost to KU and the effect on KU's business of complying with potential GHG restrictions and other environmental regulatory initiatives will depend upon provisions of any final rules and how the rules are implemented by the EPA. Some of the design elements which may have the greatest effect on KU include (a) the required levels and timing of emissions caps, discharge limits or similar standards, (b) the sources covered by such requirements, (c) transition and mitigation provisions, such as phase-in periods, free allowances or price caps, (d) the availability and pricing of relevant mitigation or control technologies, goods or services and (e) economic, market and customer reaction to electricity price and demand changes due to environmental concerns.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. Based on prior regulatory precedent, KU currently anticipates that many of such direct costs may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, but the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change and other environmental matters will likely increase the level of

capital expenditures and operating and maintenance costs incurred by the Company during the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. In order to comply with the coal combustion residual rules and the above referenced air rules, capital expenditures for KU are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary. This estimate does not include compliance with GHG rules or contemplated water-related environmental changes. See Risk Factors and Note 13, Commitments and Contingencies, for further information.

Results of Operations

The utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year. Revenue and earnings are generally highest during the first and third quarters, and lowest in the second quarter, due to weather.

<u>Net Income</u>

The following table summarizes the significant components of net income for 2010, 2009 and 2008 and the changes therein:

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Total operating revenues	$ 1,511	$ 263	$ 1,248	$1,355	$ 1,405
Total operating expenses	1,161	198	963	1,086	1,145
Operating income	350	65	285	269	260
Equity in earnings of unconsolidated venture	3	-	3	1	30
Interest expense	14	8	6	6	14
Interest expense to affiliated companies	64	2	62	69	58
Other income (expense) – net	(2)	-	(2)	5	8
Income before income taxes	273	55	218	200	226
Income tax expense	98	20	78	67	68
Net income	$ 175	$ 35	$ 140	$ 133	$ 158

The change in KU's net income was as follows:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Total operating revenues	$ 156	$ (50)
Total operating expenses	75	(59)
Operating income	81	9
Equity in earnings of unconsolidated venture	2	(29)
Interest expense	8	(8)
Interest expense to affiliated companies	(5)	11
Other income (expense) – net	(7)	(3)
Income (loss) before income taxes	73	(26)
Income taxes	31	(1)
Net income	$ 42	$ (25)

Operating Revenues

The $156 million increase from 2009 to 2010 and $50 million decrease from 2008 to 2009 in operating revenues were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Retail sales volumes (a)	$ 73	$ (43)
Base rate price variance (b)	39	(5)
Demand revenue (c)	16	(1)
Sales to municipal customers (d)	12	(1)
Increased recoverable capital spending billed through the ECR	8	50
Other operating revenue primarily due to late payment charges	6	6
FAC price variance (e)	5	(2)
Merger surcredit termination in February 2009	2	13
Transmission sales	1	-
Increased recoverable program spending billed through the DSM	1	9
Wholesale sales (f)	(7)	(77)
VDT surcredit termination in August 2008	-	1
	$ 156	$ (50)

(a) Retail sales volumes increased during 2010 compared to 2009 as a result of increased consumption primarily due to increased heating degree days during the first and fourth quarters of 2010 and increased cooling degree days during the second and third quarters of 2010. Additionally, improved economic conditions in 2010 and significant storm outages in 2009 contributed to the increased volumes.

The decrease in retail sales volumes during 2009 compared to 2008 was attributable to reduced consumption by retail customers, as a result of milder weather and weakened economic conditions, in addition to significant storm outages during 2009.

(b) The increase in revenues due to the base rate price variance during 2010 compared to 2009 resulted from higher base rates effective August 1, 2010. See Note 3, Rates and Regulatory Matters, for further discussion of the 2010 Kentucky rate case.

The decrease in revenues due to the base rate price variance during 2009 compared to 2008 resulted from a reduction in base energy rates effective February 6, 2009. See Note 3, Rates and Regulatory Matters, for further discussion of the 2008 Kentucky rate case.

(c) Demand revenues increased during 2010 compared to 2009 as a result of higher demand rates effective August 1, 2010 and higher customer peak demand. See Note 3, Rates and Regulatory Matters, for further discussion of the 2010 Kentucky rate case.

(d) The increase in sales to municipal customers during 2010 compared to 2009 was primarily due to increased volumes as a result of increased cooling and heating degree days, improved economic conditions and a decline in storm outages.

(e) FAC revenues increased during 2010 compared to 2009 as a result of increased recoverable fuel costs billed to customers through the FAC due to higher fuel prices.

The decrease in the FAC revenue during 2009 compared to 2008 resulted from lower fuel costs billed to customers through the FAC ($2 million) due to a refund of power purchased costs from OMU ($6 million) partially offset by increased recoverable fuel costs ($4 million) billed to retail customers through the FAC.

(f) The decrease in wholesale sales during 2010 compared to 2009 was primarily due to increased consumption by industrial customers, as a result of improved economic conditions, increased consumption by residential customers, as a result of increased cooling and heating degree days and an increase in LG&E’s coal-fired generation outages in the first six months of 2010. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between KU and LG&E.

The decrease in wholesale sales during 2009 compared to 2008 was primarily due to lower sales volumes to LG&E and third-parties due to lower economic capacity, caused by low spot market pricing and higher scheduled coal-fired generation outages. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between KU and LG&E.

Operating Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority. Operating expenses and the changes therein for 2010, 2009 and 2008 follow:

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Fuel for electric generation	$ 495	$ 78	$ 417	$ 434	$ 513
Power purchased	175	28	147	199	221
Other operation and maintenance expenses	346	66	280	320	275
Depreciation and amortization	145	26	119	133	136
	$ 1,161	$ 198	$ 963	$ 1,086	$ 1,145

The changes in operating expenses were as follows:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Fuel for electric generation	$ 61	$ (79)
Power purchased	(24)	(22)
Other operation and maintenance expenses	26	45
Depreciation and amortization	12	(3)
	$ 75	$ (59)

Fuel for Electric Generation

The $61 million increase from 2009 to 2010 and $79 million decrease from 2008 to 2009 were primarily due to:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Fuel usage volumes (a)	$ 77	$ (97)
Commodity costs for coal	(15)	18
Other	(1)	-
	$ 61	$ (79)

(a) Fuel usage volumes increased in 2010 compared 2009 due to increased native load sales. Fuel usage volumes decreased in 2009 compared to 2008 due to decreased native load and wholesale sales.

Power Purchased Expense

The $24 million decrease from 2009 to 2010 and $22 million decrease from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Power purchased from OMU	$ (40)	$ 12
Purchases from LG&E due to volume (a)	(5)	(2)
Demand payments for third party purchases	(2)	1
Prices for purchases used to serve retail customers	7	(14)
Third party purchased volumes for native load (b)	7	(6)
OMU settlement received in 2009	6	(6)
Purchases from LG&E due to prices	3	(7)
	$ (24)	$ (22)

(a) Purchased volumes from LG&E decreased in 2010 compared to 2009 primarily due to increased consumption by residential customers at LG&E as the result of increased cooling and heating degree days, increased coal-fired generation outages in the first six months of 2010 and higher energy usage by industrial customers as a result of improved economic conditions.

Purchased volumes from LG&E decreased in 2009 compared to 2008 due to LG&E's increased scheduled outages at coal-fired generation units during the fourth quarter of 2009. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between the Utilities.

(b) Third party purchase volumes with counterparties other than OMU increased in 2010 compared to 2009 primarily due to the termination of the OMU agreement. Third party purchase volumes with counterparties other than OMU decreased in 2009 compared to 2008 primarily due to availability of power for native load customers from the OMU agreement. See Note 13, Commitments and Contingencies, for further discussion of the OMU settlement.

Other Operation and Maintenance Expenses

The $26 million increase from 2009 to 2010 was primarily due to $22 million of increased other operation expenses and $4 million of increased maintenance expenses. The $45 million increase from 2008 to 2009 was primarily due to $30 million of increased other operation expenses and $15 million of increased maintenance expenses.

Other Operation Expenses:

The $22 million increase from 2009 to 2010 and $30 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Administrative and general expense (a)	$ 9	$ 3
Transmission expense (b)	5	-
Bad debt expense (c)	4	(1)
Steam expense (d)	4	7
Generation expense	2	(2)
DSM program spending	-	9
Legal expenses (e)	-	(6)
Other power supply	(1)	-
Pension expense (f)	(2)	20
Other	1	-
	$ 22	$ 30

(a) Administrative and general expense increased in 2010 compared 2009 primarily due to higher labor expense and insurance expense, partially offset by lower IT expense related to the implementation of the Customer Care Solution system in 2009. Administrative and general expense increased in 2009 compared to 2008 primarily due to increased consulting fees for software training and increased labor and benefit costs.
(b) Transmission expense increased in 2010 compared to 2009 primarily due to a settlement agreement with a third party and the establishment of a regulatory asset approved by the Kentucky Commission for the EKPC settlement in 2009, net of twelve months of amortization expense recorded in 2010.
(c) Bad debt expense increased in 2010 compared to 2009 due to higher billed revenues, higher late payment charges and a higher net charge-off percentage.
(d) Steam expense increased in 2010 compared to 2009 primarily due to increased generation in 2010. Steam expense increased in 2009 compared to 2008 primarily due to the utilization of SCRs year-round.
(e) Legal expenses decreased in 2009 compared to 2008 primarily due to OMU expenses in 2008. See Note 13, Commitments and Contingencies, for further information regarding the OMU settlement.
(f) Pension expense decreased in 2010 compared to 2009 primarily due to favorable asset performance in 2009 and increased in 2009 compared to 2008 primarily due to unfavorable asset performance in 2008.

Other Maintenance Expenses:

The $4 million increase from 2009 to 2010 and $15 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Generation expense (a)	$ 3	$ -
Steam expense (b)	2	7
Administrative and general expense	2	1
Transmission expense	-	2
Distribution expense (c)	(3)	5
	$ 4	$ 15

(a) Generation expense increased in 2010 compared to 2009 primarily due to the overhaul of Paddy's Run Unit 13.
(b) Steam expense increased in 2009 compared to 2008 due to increased scope of work for scheduled outages.
(c) Distribution expense decreased in 2010 compared to 2009 primarily due to higher storm cost in 2009, partially offset by higher tree trimming expense in 2010. Distribution expense increased in 2009 compared to 2008 primarily due to increased repairs, higher tree trimming expense and higher storm related expense.

Equity in Earnings of Unconsolidated Venture

The $2 million increase in equity in earnings of unconsolidated venture, from 2009 to 2010, was primarily due to higher earnings from EEI resulting from increased market prices for electric energy and the $29 million decrease from 2008 to 2009 was primarily due to lower earnings resulting from decreased market prices for electric energy.

Interest Expense

The $3 million increase from 2009 to 2010 and $3 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Bond interest expense (a)	$ 8	$ (8)
Interest expense to affiliated companies (b)	(5)	11
	$ 3	$ 3

(a) Bond interest expense increased in 2010 compared to 2009 due to the issuance of first mortgage bonds in November 2010. Bond interest expense decreased in 2009 compared to 2008 due to lower interest rates on pollution control bonds. See Note 11, Long-Term Debt, for further information.
(b) Interest expense to affiliated companies decreased in 2010 compared to 2009 primarily due to notes payable to Fidelia being paid in full in November 2010, as a result of the PPL acquisition. Interest expense to affiliated companies increased in 2009 compared to 2008 primarily due to the

issuance of additional debt ($13 million), which was partially offset by lower interest rates on intercompany short-term borrowings.

Other Income (Expense) – Net

The $7 million decrease in other income (expense) – net from 2009 to 2010 and the $3 million decrease in other income (expense) – net from 2008 to 2009 were primarily due to the discontinuance of the allowance for funds used during construction on ECR projects as a result of the FERC rate case.

Income Tax Expense

See Note 10, Income Taxes, for a reconciliation of differences between the U.S. federal income tax expense at statutory rates and KU's income tax expense.

2011 Outlook

KU projects higher earnings in 2011 compared with 2010 as a net result of higher retail revenues and lower financing costs due to the issuance of first mortgage bonds in late 2010, partially offset by higher operation and maintenance expenses and depreciation. Retail revenues are expected to increase as a result of the 2010 Kentucky rate case and recoveries associated with its environmental investments. Operation and maintenance expenses and depreciation are expected to increase due to placing TC2 in service in January 2011. See Risk Factors for a discussion of the risk factors that may impact the 2011 outlook.

Financial Condition

Liquidity and Capital Resources

KU expects to continue to have adequate liquidity available through operating cash flows, cash and cash equivalents and its credit facilities. KU currently has no plans to access debt capital markets in 2011.

KU's cash flows from operations and access to cost-effective bank and capital markets are subject to risks and uncertainties including, but not limited to, the following:

- changes in market prices for electricity;
- potential ineffectiveness of the trading, marketing and risk management policy and programs used to mitigate KU's risk exposure to adverse electricity and fuel prices and interest rates;
- operational and credit risks associated with selling and marketing products in the wholesale power markets;
- unusual or extreme weather that may damage KU's transmission and distribution facilities or affect energy sales to customers;
- unavailability of generating units (due to unscheduled or longer than anticipated generation outages, weather and natural disasters) and the resulting loss of revenues and additional costs of replacement electricity;
- ability to recover and timeliness and adequacy of recovery of costs;
- costs of compliance with existing and new environmental laws;

- any adverse outcome of legal proceedings and investigations with respect to KU's current and past business activities;
- deterioration in the financial markets that could make obtaining new sources of bank and capital markets funding more difficult and more costly; and
- a downgrade in KU's credit ratings that could adversely affect its ability to access capital and increase the cost of credit facilities and any new debt.

See the Risk Factors section for further discussion of risks and uncertainties affecting KU's cash flows.

At December 31, KU had the following:

	Successor	Predecessor
	2010	2009
Cash and cash equivalents	$ 3	$ 2
Current portion of long-term debt (a)	$ -	$ 228
Current portion of long-term debt to affiliated company (b)	-	33
Notes payable to affiliated companies (c)	10	45
	$ 10	$ 306

(a) 2009 amount represents Carroll County 2002 Series A and B, 2004 Series A, 2006 Series B and 2008 Series A; Muhlenberg County 2002 Series A; and Mercer County 2000 Series A and 2002 Series A pollution control bonds subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. The Successor has classified these bonds as long-term because the Company has the intent and ability to utilize its $400 million credit facility which matures in December 2014, to fund any mandatory purchases. The Predecessor classified these bonds as the current portion of long-term debt due to the tender for purchase provisions. The Predecessor presentation and the Successor presentation are both appropriate under GAAP. See Note 1, Summary of Significant Accounting Policies, and Note 11, Long-Term Debt, for further information.

(b) 2009 amount represents debt owed to an E.ON affiliate, which was repaid in November 2010. See Note 11, Long-Term Debt, for further information.

(c) Amounts represent borrowings under KU's intercompany money pool agreement wherein LKE and/or LG&E make funds available to KU at market-based rates of up to $400 million. See Note 12, Notes Payable and Other Short-Term Obligations, for further information.

A condensed table of cash flows for the following periods in 2010, 2009 and 2008 is presented below. The Predecessor period, January 1, 2010 through October 31, 2010, and the Successor period, November 1, 2010 through December 31, 2010, were aggregated without further adjustment for purposes of comparison with the same periods in 2009 and 2008.

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Net cash provided by (used in) operating activities	$ 372	$ 28	$ 344	$ 253	$ 292
Net cash provided by (used in) investing activities	(427)	(87)	(340)	(507)	(695)
Net cash provided by (used in) financing activities	56	58	(2)	254	405
Change in cash and cash equivalents	$ 1	$ (1)	$ 2	$ -	$ 2

Operating Activities

Net cash provided by operating activities increased by 47%, or $119 million, in 2010 compared with 2009, primarily as a result of increased earnings, increased collections from the ECR mechanism and lower storm expenses. These increases in cash flow were partially offset by higher interest payments due to an accelerated settlement with the previous owner and higher 2010 income tax payments due to higher taxable income and investment tax credit benefits received in 2009.

Net cash provided by operating activities decreased by 13%, or $39 million, in 2009 compared with 2008, primarily as a result of higher storm expenses, decreased earnings and unfavorable changes in working capital. These decreases in cash flow were partially offset by lower income tax payments due to lower taxable income and investment tax credit benefits received.

KU expects to achieve relatively stable cash flows from operations during the next three years although future cash flows may be significantly impacted by changes in economic conditions or new environmental and tax regulations.

Investing Activities

The primary use of cash in investing activities is capital expenditures. See “Forecasted Uses of Cash" for detail regarding projected capital expenditures for the years 2011 through 2013.

Net cash used in investing activities decreased by 16%, or $80 million, in 2010 compared with 2009, primarily as a result of a decrease of $89 million in capital expenditures, partially offset by a decrease of $9 million from restricted cash collections.

Net cash used in investing activities decreased by 27%, or $188 million, in 2009 compared with 2008, primarily as a result of a decrease of $180 million in capital expenditures and a increase of $8 million from restricted cash collections.

Financing Activities

Net cash provided by financing activities was $56 million in 2010 compared with $254 million in 2009. In spite of significant new debt issuances associated with the repayments to E.ON affiliates in connection with PPL's acquisition of the Company, cash provided by financing was less in 2010 due to lower increases in debt in 2010 and the payment of dividends in 2010; whereas, KU received equity contributions in 2009.

Net cash provided by financing activities was $254 million in 2009 compared with $405 million in 2008. The lower level of cash provided by financing in 2009 was the result of lower debt issuance to affiliated companies and lower levels of equity contributions received.

In the two months of 2010 following the acquisition, cash provided by financing activities of the Successor primarily consisted of the issuance of first mortgage bonds totaling $1,489 million after discounts and the issuance of intercompany notes totaling $1,331 million to a PPL subsidiary to repay debt due to an E.ON affiliate upon the closing of the sale. These amounts were offset by the repayment of $1,331 million to an E.ON affiliate upon the closing of the sale, the repayment of $1,331 million to a PPL affiliate upon the issuance of the first mortgage bonds, the repayment of $83 million of short-term borrowings due to an affiliated company and the payment of $17 million of debt issuance costs.

In 2010, cash used in financing activities by the Predecessor primarily consisted of the payment of $50 million of dividends to LKE mostly offset by increases in short-term borrowings due to an affiliated company totaling $48 million.

In 2009, cash provided by financing activities primarily consisted of the issuance of $150 million of intercompany notes to an E.ON affiliate, the receipt of capital contributions from LKE totaling $75 million and a $29 million increase in short-term borrowings due to an affiliated company.

In 2008, cash provided by financing activities primarily consisted of the issuance of $250 million of intercompany notes to an E.ON affiliate, the receipt of capital contributions from LKE totaling $145 million and a $7 million reduction in short-term borrowings due to an affiliated company. In addition, KU reacquired pollution control bonds totaling $80 million, reissued $63 million of that $80 million and issued $77 million of new pollution control bonds. Of the $77 million, $60 million was used to retire prior pollution control bonds, including the remaining $17 million which had been reacquired by the Company. This resulted in a cash receipt of $17 million to KU.

KU's debt financing activity in 2010 was:

	Issuances (a)	Retirements
Short-term borrowings from affiliated company – net change	$ -	$ (35)
Other borrowings from affiliated company	1,331	(1,331)
Borrowings from an E.ON affiliate	-	(1,331)
Issuance of bonds	1,489	-
Net change in debt financing	$ 2,820	$ (2,697)

(a) Issuances are net of pricing discounts, where applicable.

See Note 11, Long-Term Debt, for further information.

Working Capital Deficiency

As of December 31, 2009, KU had a working capital deficiency of $203 million, primarily due to the current portion of long-term debt to affiliated company totaling $33 million and $228 million of tax-exempt bonds which allow the investors to put the bonds back to the Company causing them to be classified as "Current portion of long-term debt." As of December 31, 2010, the Company no longer had a working capital deficiency because the current portion of long-term debt to affiliated company was paid off in conjunction with the PPL acquisition, and the $228 million of tax-exempt bonds were no longer classified as "Other current liabilities" by the Successor because the Company has the intent and ability to utilize its $400 million credit facility which expires in December 2014 to fund any mandatory purchases. See Note 11, Long-Term Debt, for further information.

Auction Rate Securities

Auctions for auction rate securities issued by KU continued to fail throughout 2010. See Note 11, Long-Term Debt, for further discussion.

Forecasted Sources of Cash

KU expects to continue to have adequate sources of cash available in the near term, including access to external financing, financing from affiliates and/or infusions of capital from LKE. Regulatory approvals are required for KU to incur additional debt. The FERC and the Virginia Commission authorize the issuance of short-term debt while the Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority authorize the issuance of long-term debt. In November 2009, KU received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. KU also has authorization from the Virginia Commission that expires at the end of 2011, allowing short-term borrowing of up to $400 million. Short-term funds are made available via the Company's participation in an intercompany money pool agreement wherein LKE and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) up to $400 million or via the $400 million Revolving Credit Agreement discussed below. KU currently believes this authorization and these facilities, together with the Company's credit facilities discussed below, provide the necessary flexibility to address any liquidity needs.

Credit Facilities

On November 1, 2010, KU entered into a $400 million unsecured Revolving Credit Agreement with a group of banks. Under this new credit facility, which expires on December 31, 2014, KU has the ability to make cash borrowings and to request the lenders to issue letters of credit. Borrowings will generally bear interest at LIBOR-based rates plus a spread, depending upon KU's senior unsecured long-term debt rating. The new credit facility contains financial covenants requiring KU's debt to total capitalization to not exceed 70% and other customary covenants. As of December 31, 2010, KU's debt to total capitalization was 41% as calculated pursuant to the credit agreement. Under certain conditions, KU may request that the facility's capacity be increased by up to $100 million. This new credit facility

replaced an existing bilateral line of credit totaling $35 million that was terminated November 1, 2010. As of December 31, 2010, there was no outstanding balance under the new credit facility, but there were $198 million of letters of credit outstanding to support outstanding bonds totaling $195 million. KU will utilize unused credit facility and money pool balances to fund working capital needs as they arise. See Note 12, Notes Payable and Other Short-Term Obligations, for further information regarding the Company's credit facilities.

Contributions from LKE

LKE may make capital contributions to KU, which can be used for general business purposes.

Long-Term Debt

KU currently does not plan to issue any new long-term debt in 2011.

Forecasted Uses of Cash

In addition to expenditures required for normal operating activities, such as fuel for electric generation, power purchased, payroll and taxes; KU currently expects to incur future cash outflows for capital expenditures, various contractual obligations and the payment of dividends.

Capital Requirements

KU's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of its service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. KU plans to fund capital expenditures through operating cash flows, the credit facility and, if needed, the issuance of long-term debt. KU expects its capital expenditures for the three year period ending December 31, 2013, to total approximately $1,406 million, consisting primarily of the following:

Construction of coal combustion residual storage structures	$	346
Construction of environmental controls and capacity replacement		302
Construction of distribution and metering assets		260
Construction of generation assets		206
Construction of transmission assets		129
Recoverable environmental assets		99
Information technology projects		39
Other projects		25
	$	1,406

The Company's capital program will focus primarily on compliance with existing or anticipated EPA environmental regulations, aging infrastructure and the need for increased storage capacity for coal combustion by-product materials over the next several years. This program may also be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, changes in commodity prices and labor rates and other regulatory requirements. In particular, climate change initiatives, whether via legislative, regulatory or market channels, could restrict or disadvantage power generation from higher-

carbon sources. Therefore, KU has included estimates regarding significant additional capital expenditures related to pending environmental regulations and legislation. These estimates are subject to final regulations and least cost analysis based on engineering studies. To the extent financial markets see climate change as a potential risk, KU may face reduced access to or increased costs in capital markets. Capital expenditures for KU associated with such actions are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary.

See the Contractual Obligations table below and Note 13, Commitments and Contingencies, for further information concerning commitments.

Contractual Obligations

The following is provided to summarize contractual cash obligations for periods after December 31, 2010. KU anticipates cash from operations and external financing will be sufficient to fund future obligations. See the Statements of Capitalization.

	Payments Due by Period						
	2011	2012	2013	2014	2015	Thereafter	Total
Short-term debt (a)	$ 10	$ -	$ -	$ -	$ -	$ -	$ 10
Long-term debt (b)	-	-	-	-	250	1,601	1,851
Interest on long-term debt (c)	67	69	72	75	78	1,414	1,775
Operating leases (d)	8	7	5	5	3	1	29
Unconditional power purchase obligations (e)	9	10	10	10	10	114	163
Coal and natural gas purchase obligations (f)	439	200	144	93	91	14	981
Pension benefit plan obligations (g)	18	24	28	10	7	60	147
Postretirement benefit plan obligations (h)	5	6	6	6	6	33	62
Construction obligations (i)	113	3	-	-	-	-	116
Other obligations (j)	3	3	-	-	-	-	6
	$ 672	$ 322	$ 265	$ 199	$ 445	$ 3,237	$ 5,140

This table does not reflect contingent obligations. See Note 13, Commitments and Contingencies, for further information on contingent obligations.

(a) Represents borrowings due to affiliates within one year.
(b) Reflects principal maturities only based on legal maturity dates and includes the current portion of long-term debt.
(c) Assumes interest payments through maturity. The payments herein are subject to change as payments for debt that is or becomes variable-rate debt have been estimated.
(d) Represents future operating lease payments.
(e) Represents future minimum payments under OVEC power purchase agreements through March 13, 2026.
(f) Represents contracts to purchase coal, natural gas and natural gas transportation.

(g) Represents projected cash flows for funding the pension benefit plans as calculated by the actuary. For pension funding information see Note 9, Pension and Other Postretirement Benefit Plans.
(h) Represents projected cash flows for the postretirement benefit plan as calculated by the actuary. For postretirement funding information, see Note 9, Pension and Other Postretirement Benefit Plans.
(i) Represents construction commitments, including commitments for the Brown SCR and the Brown and Ghent landfill construction including associated material transport systems for coal combustion residual.
(j) Represents other contractual obligations including the SPP and TVA coordination agreements.

Pension and Postretirement Benefit Plans

See Application of Critical Accounting Policies and Estimates for discussion regarding discretionary contributions to the pension and postretirement benefit plans in 2011.

Dividends

Future dividends may be declared at the discretion of KU's Board of Directors, payable to its sole shareholder, LKE. As discussed in Note 12, Notes Payable and Other Short-Term Obligations, KU's dividend payments are limited under a covenant in its $400 million revolving line of credit facility. This covenant restricts the debt to total capital ratio to not more than 70%. KU is subject to Section 305(a) of the Federal Power Act, which makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in capital account." The meaning of this limitation has never been clarified under the Federal Power Act. KU believes, however, that this statutory restriction, as applied to its circumstances, would not be construed or applied by the FERC to prohibit the payment from retained earnings of dividends that are not excessive and are for lawful and legitimate business purposes.

Purchase, Redemption or Remarketing of Debt Securities

KU will continue to evaluate purchasing, redeeming or remarketing outstanding debt securities and may decide to take action depending upon prevailing market conditions and available cash.

Credit Ratings

KU's credit ratings reflect the views of three national rating agencies. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. In October 2010, one national rating agency revised downward the short-term credit rating of the pollution control bonds and the issuer rating of the Company as a result of the then pending acquisition by PPL. Another raised the long-term rating of the pollution control bonds as a result of the addition of the first mortgage bonds as collateral. In October 2010, a third national rating agency provided an initial rating of the Company's pollution control bonds and first mortgage bonds. See Note 11, Long-Term Debt, for a discussion of downgrade actions in 2009 and 2008 related to the pollution control bonds caused by a change in the rating of the entity insuring those bonds.

Ratings Triggers

KU has various derivative and non-derivative contracts, including contracts for the sale and purchase of electricity and fuel and commodity transportation, which contain provisions requiring KU to post additional collateral, or permit the counterparty to terminate the contract if KU's credit rating were to fall below investment grade. See Note 5, Derivative Financial Instruments, for a discussion of Credit Risk Related Contingent Features, including a discussion of the potential additional collateral that would have been required for derivative contracts in a net liability position at December 31, 2010. At December 31, 2010, if KU's credit ratings had been below investment grade, KU would have been required to prepay or post an additional $16 million of collateral to counterparties for both derivative and non-derivative commodity and commodity-related contracts used in its generation, marketing and trading operations.

Off-Balance Sheet Arrangements

KU has very limited off-balance sheet activity. See Note 13, Commitments and Contingencies, for further discussion.

Risk Management

Credit Risk

KU is exposed to potential losses as a result of nonperformance by counterparties of their contractual obligations. KU maintains credit policies and procedures to limit counterparty credit risk including evaluating credit ratings and financial information along with having certain counterparties post margin if the credit exposure exceeds certain thresholds. See Note 5, Derivative Financial Instruments, for information regarding risk management activities.

KU is exposed to potential losses as a result of nonpayment by customers. The Company maintains an allowance for doubtful accounts composed of accounts aged more than four months. Accounts are written off as management determines them uncollectible. See Application of Critical Accounting Policies and Estimates and Note 1, Summary of Significant Accounting Policies, for further discussion.

Certain of the Company's derivative instruments contain provisions that require it to provide immediate and on-going collateralization on derivative instruments in net liability positions based upon the Company's credit ratings from each of the major credit rating agencies. See Note 5, Derivative Financial Instruments, for information regarding exposure and the risk management activities.

Liquidity Risk

KU expects to continue to have access to adequate sources of liquidity through operating cash flows, cash and cash equivalents, credit facilities and/or infusion of capital from its parent. See Financial Condition - Liquidity and Capital Resources for an expanded discussion of KU's liquidity position and a discussion of its forecasted sources of cash.

Securities Price Risk

KU has securities price risk through its participation in defined benefit pension and postretirement benefit plans. Declines in the market price of debt and equity securities could impact contribution requirements. See Application of Critical Accounting Policies and Estimates - Defined Benefits for a discussion of the assumptions and sensitivities regarding the defined benefit pension and postretirement benefit plans assumptions.

Interest Rate and Commodity Price Risk

KU is subject to interest rate and commodity price risk related to on-going business operations. It currently manages commodity risks using derivative instruments, including swaps and forward contracts. The Company's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At December 31, 2010, no interest rate swaps were in effect for KU. At December 31, 2010, the Company's annual exposure to increased interest expense, based on a 10% increase in interest rates, was less than $1 million.

KU manages price risk by conducting energy trading activities through forward financial transactions. The following chart sets forth the net fair value of KU's commodity derivative contracts. See Note 5 Derivative Financial Instruments, for further information.

	Successor	Predecessor	
	December 31, 2010 (a)	October 31, 2010 (a)	December 31, 2009
Fair value of contracts outstanding at the beginning of the period	$ -	$ -	$ 1
Contracts realized or otherwise settled during the period	-	-	
Fair value of new contracts entered into during the period	-	-	-
Changes in fair value attributable to changes in valuation techniques	-	-	-
Other changes in fair value	-	-	(1)
Fair value of contracts outstanding at the end of the period	$ -	$ -	$ -

(a) 2010 activity is less than $1 million.

Related Party Transactions

KU and its Parent, LKE and subsidiaries of LKE engage in related party transactions. See Note 15, Related Party Transactions, for further information.

KU is not aware of any material ownership interest or operating responsibility by the executive officers of KU in outside partnerships, including leasing transactions with variable interest entities, or entities doing business with KU.

Acquisitions, Development and Divestitures

KU and LG&E have been constructing a new 760-Mw capacity base-load, coal-fired unit, TC2, which is jointly owned by KU (60.75%) and LG&E (14.25%), together with IMEA and IMPA (combined 25%). With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. See Note 13, Commitments and Contingencies, for further information.

KU continuously re-examines development projects based on market conditions and other factors to determine whether to proceed, to cancel or to expand the projects.

Application of Critical Accounting Policies and Estimates

The financial statements of KU are prepared in compliance with GAAP. The application of these principles necessarily involves judgments regarding future events, including legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but also on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied has not changed. KU's senior management has reviewed the significant and critical accounting policies with the relevant governing bodies of the Company and its parent, as applicable.

An accounting policy is deemed to be critical if it requires an accounting estimate to be made based on assumptions about matters that are highly uncertain at the time the estimate is made, if different estimates reasonably could have been used or if changes in the estimate that are reasonably possible could materially impact the financial statements. Management believes the following critical accounting policies reflect the significant estimates and assumptions used in the preparation of the Financial Statements.

Price Risk Management

See Financial Condition - Risk Management.

Regulatory Mechanisms

KU is a cost-based rate-regulated utility. As a result, the financial statements reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise be charged to expense. Likewise, regulatory liabilities are recognized for obligations expected to be returned through future regulated customer rates. The effect of such transactions or events would otherwise be reflected as income. In certain cases, regulatory liabilities are recorded based on the understanding with the regulator that current rates are being set to recover costs that are expected to be incurred in the future. The regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. The accounting

for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC, the Kentucky Commission, the Virginia Commission or the Tennessee Regulatory Authority. See Note 3, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Defined Benefits

KU employees benefit from both funded and unfunded retirement benefit plans. See Note 1, Summary of Significant Accounting Policies, for information about policy changes between the Predecessor and Successor and the accounting for defined benefits including KU's method of amortizing gains and losses. KU makes various assumptions in arriving at pension and other postretirement benefit costs and obligations. The major assumptions include:

- KU's selection of discount rates is based on the Mercer Pension Discount Yield Curve (Predecessor) and the Towers Watson Yield Curve (Successor).
- KU's selection of rate of salary growth is based on historical data that includes employees' periodic pay increases and promotions, which are used to project employees' pension benefits at retirement.
- KU determines the expected long-term return on plan assets based on the current level of expected return on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class is then weighted based on the current asset allocation.
- KU's management projects health care cost trends based on past health care costs, the near-term outlook and an assessment of likely long-term trends.

The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under the defined benefit pension plans. The return on investments within the plans was approximately 12% for the year ended December 31, 2010. The benefit plan assets and obligations are re-measured annually using a December 31 measurement date. Due to the PPL acquisition, the benefit plan assets and obligations were also re-measured at October 31, 2010. The Company's 2010 pension cost was approximately $3 million less than 2009. The Company anticipates its 2011 pension cost will be approximately $3 million less than the 2010 expense. The amount of future funding will depend upon the actual return on plan assets, the discount rate and other factors, but the Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. The Company made discretionary contributions to its pension plan of $13 million in 2010 and 2009, respectively. In January 2011, KU contributed $43 million to its pension plan. See Note 18, Subsequent Events, for further information.

See Note 9, Pension and Other Postretirement Benefit Plans, for further information on defined benefits including sensitivity analysis expressing potential changes in expected returns that would result from hypothetical changes to assumptions and estimates, expected rate of return assumptions and health care trends.

Asset Impairment

KU performs a quarterly review to determine if an impairment analysis is required for long-lived assets that are subject to depreciation or amortization. This review identifies changes in circumstances indicating that a long-lived asset's carrying value may not be recoverable. An impairment analysis will be performed if warranted based on the review. For these long-lived assets, such events or changes in circumstances which may indicate an impairment analysis is required include:

- a significant decrease in the market price of an asset;
- a significant adverse change in the manner in which an asset is being used or in its physical condition;
- a significant adverse change in legal factors or in the business climate;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of an asset;
- a current-period operating or cash flow loss combined with a history of losses or a forecast that demonstrates continuing losses;
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its previously estimated useful life; and
- a significant change in the physical condition of an asset.

For a long-lived asset, impairment is recognized when the carrying amount of the asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset is impaired, an impairment loss is recorded to adjust the asset's carrying value to its estimated fair value. Management must make significant judgments to estimate future cash flows including the useful lives of long-lived assets, the fair value of the assets and management's intent to use the assets. KU did not recognize an impairment of any long-lived asset in 2010.

Effective with PPL's acquisition of LKE on November 1, 2010, KU recorded $607 million of goodwill. At December 31, 2010, KU's goodwill remained unchanged. GAAP requires goodwill to be tested for impairment on an annual basis or more frequently if events or circumstances indicate that assets may be impaired. KU performs its annual goodwill impairment test in the fourth quarter. See Note 7, Goodwill and Intangible Assets, for further discussion.

Goodwill is tested for impairment using a two-step approach. In step 1, the Company identifies a potential impairment by comparing the estimated fair value of the Company (the goodwill reporting unit) to its carrying value, including goodwill, on the measurement date. If the estimated fair value exceeds its carrying amount, goodwill is not considered impaired. If the carrying amount exceeds the estimated fair value, the second step is performed to measure the amount of impairment loss, if any.

The second step requires a calculation of the implied fair value of goodwill. The implied fair value of goodwill is determined in the same manner as the amount of goodwill in a business combination. That is, the estimated fair value is allocated to all of KU's assets and liabilities as if KU had been acquired in a business combination and the estimated fair value of KU was the price paid. The excess of the estimated fair value of KU over the amounts assigned to its assets and liabilities is the implied fair value of goodwill. The implied fair value of goodwill is then compared with the carrying amount of that goodwill. If the

carrying amount exceeds the implied fair value, an impairment loss is recognized in an amount equal to that excess. The loss recognized cannot exceed the carrying amount of the reporting unit's goodwill.

Determining the fair value of KU is judgmental in nature and involves the use of significant estimates and assumptions. These estimates and assumptions can include revenue growth rates and operating margins used to calculate projected future cash flows, risk adjusted discount rates and future economic and market conditions.

KU tested goodwill for impairment in the fourth quarter of 2010 and no impairment was recognized. See Note 7, Goodwill and Intangible Assets, for further discussion.

Loss Accruals

KU accrues losses for the estimated impacts of various conditions, situations or circumstances involving uncertain or contingent future outcomes. For loss contingencies, the loss must be accrued if (1) information is available that indicates it is probable that a loss has been incurred, given the likelihood of the uncertain future events and (2) the amount of the loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." KU does not record the accrual of contingencies that might result in gains, unless recovery is assured. KU continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events.

The accounting aspects of estimated loss accruals include (1) the initial identification and recording of the loss, (2) the determination of triggering events for reducing a recorded loss accrual and (3) the ongoing assessment as to whether a recorded loss accrual is sufficient. All three of these aspects require significant judgment by KU's management. KU uses its internal expertise and outside experts (such as lawyers and engineers), as necessary, to help estimate the probability that a loss has been incurred and the amount or range of the loss.

KU has identified certain other events that could give rise to a loss, but that do not meet the conditions for accrual. Such events are disclosed, but not recorded, when it is reasonably possible that a loss has been incurred. Accounting guidance defines "reasonably possible" as cases in which "the future event or events occurring is more than remote, but less than likely to occur." See Note 13, Commitments and Contingencies, for disclosure of other potential loss contingencies that have not met the criteria for accrual.

When an estimated loss is accrued, KU identifies, where applicable, the triggering events for subsequently adjusting the loss accrual. The triggering events generally occur when the contingency has been resolved and the actual loss is incurred, or when the risk of loss has diminished or been eliminated. The following are some of the triggering events that provide for the adjustment of certain recorded loss accruals:

- Allowances for uncollectible accounts are reduced when accounts are written off after prescribed collection procedures have been exhausted, a better estimate of the allowance is determined or underlying amounts are ultimately collected.
- Environmental and other litigation contingencies are reduced when the contingency is resolved, KU makes actual payments, a better estimate of the loss is determined or the loss is no longer considered probable.

KU reviews its loss accruals on a regular basis to assure that the recorded potential loss exposures are appropriate. This involves ongoing communication and analyses with internal and external legal counsel, engineers, operation management and other parties. This review may result in the increase or decrease of the loss accrual.

Asset Retirement Obligations

KU is required to recognize a liability for legal obligations associated with the retirement of long-lived assets. The initial obligation is measured at its estimated fair value. An equivalent amount is recorded as an increase in the value of the capitalized asset and allocated to expense over the useful life of the asset. Until the obligation is settled, the liability is increased, through the recognition of accretion expense in the Statements of Income, for changes in the obligation due to the passage of time. An offsetting regulatory asset is recognized to reverse the depreciation and accretion expense related to the ARO such that there is no income statement impact. The regulatory asset is relieved when the ARO has been settled. An ARO must be recognized when incurred if the fair value of the ARO can be reasonably estimated.

In determining AROs, management must make significant judgments and estimates to calculate fair value. Fair value is developed using an expected present value technique based on assumptions of market participants that considers estimated retirement costs in current period dollars that are inflated to the anticipated retirement date and then discounted back to the date the ARO was incurred. Changes in assumptions and estimates included within the calculations of the fair value of AROs could result in significantly different results than those identified and recorded in the financial statements. Estimated ARO costs and settlement dates, which affect the carrying value of various AROs and the related assets, are reviewed periodically to ensure that any material changes are incorporated into the estimate of the obligations. Any change to the capitalized asset is amortized over the remaining life of the associated long-lived asset. See Note 4, Asset Retirement Obligations, for further information on AROs.

At December 31, 2010, KU had AROs totaling $54 million recorded on the Balance Sheets. Of the total amount, $35 million, or 65%, relates to KU’s ash ponds and landfills. The most significant assumptions surrounding AROs are the forecasted retirement costs, the discount rates and the inflation rates. A variance in the forecasted retirement costs, the discount rates or the inflation rates could have a significant impact on the ARO liabilities.

The following chart reflects the sensitivities related to KU’s ARO liabilities for ash ponds and landfills as of December 31, 2010:

	Change in Assumption	Impact on ARO Liability
Retirement cost	10%/(10)%	$4/$(4)
Discount rate	0.25%/(0.25)%	$(2)/$1
Inflation rate	0.25%/(0.25)%	$2/$(2)

Income Tax Uncertainties

Significant management judgment is required in developing KU's provision for income taxes primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and the determination of deferred tax assets, liabilities and valuation allowances.

Significant management judgment is required to determine the amount of benefit recognized related to an uncertain tax position. KU evaluates its tax positions following a two-step process. The first step requires an entity to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires an entity to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. KU's management considers a number of factors in assessing the benefit to be recognized, including negotiation of a settlement.

On a quarterly basis, KU reassesses its uncertain tax positions by considering information known at the reporting date. Based on management's assessment of new information, KU may subsequently recognize a tax benefit for a previously unrecognized tax position, de-recognize a previously recognized tax position or re-measure the benefit of a previously recognized tax position. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact KU financial statements in the future.

The balance sheet classification of unrecognized tax benefits and the need for valuation allowances to reduce deferred tax assets also require significant management judgment. KU classifies unrecognized tax benefits as current, to the extent management expects to settle an uncertain tax position, by payment or receipt of cash, within one year of the reporting date. Valuation allowances are initially recorded and reevaluated each reporting period by assessing the likelihood of the ultimate realization of a deferred tax asset. Management considers a number of factors in assessing the realization of a deferred tax asset, including the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies. Any tax planning strategy utilized in this assessment must meet the recognition and measurement criteria utilized by KU to account for an uncertain tax position. See Note 10, Income Taxes, for the required disclosures.

At December 31, 2010, KU's existing reserve exposure to either increases or decreases in unrecognized tax benefits during the next 12 months is less than $1 million. This change could result from subsequent recognition, de-recognition and/or changes in the measurement of uncertain tax positions. The events that could cause these changes are direct settlements with taxing authorities, litigation, legal or administrative guidance by relevant taxing authorities and the lapse of an applicable statute of limitations.

Purchase Price Allocation

On November 1, 2010, PPL completed the acquisition of KU's parent. In accordance with accounting guidance on business combinations, the identifiable assets acquired and the liabilities assumed were measured at fair value at the acquisition date. Fair value is defined as the price that would be received to

sell an asset or paid to transfer a liability in an orderly transaction between market participants. The excess of the purchase price over the estimated fair value of the identifiable net assets is recorded as goodwill.

The determination and allocation of fair value to the identifiable assets acquired and liabilities assumed was based on various assumptions and valuation methodologies requiring considerable management judgment, including estimates based on key assumptions of the acquisition and historical and current market data. The most significant variables in these valuations were the discount rates, the number of years on which to base cash flow projections, as well as the assumptions and estimates used to determine cash inflows and outflows. Although the assumptions applied were reasonable based on information available at the date of acquisition, actual results may differ from the forecasted amounts and the difference could be material.

For purposes of measuring the fair value of the majority of property, plant and equipment and regulatory assets acquired and regulatory liabilities assumed, KU determined that fair value was equal to net book value at the acquisition date because KU's operations are conducted in a regulated environment and the regulatory commissions allow for earning a rate of return on the book value of a majority of the regulated asset bases at rates determined to be fair and reasonable. As there is no current prospect for deregulation in KU's operating area, it is expected that these operations will remain in a regulated environment for the foreseeable future, therefore management has concluded that the use of these assets in the regulatory environment represents their highest and best use and a market participant would measure the fair value of these assets using the regulatory rate of return as the discount rate, thus resulting in fair value equal to book value.

The fair value of intangible assets and liabilities (e.g. contracts that have favorable or unfavorable terms relative to market), including coal contracts and power purchase agreements, as well as emission allowances, have been reflected on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the acquisition. As a result, management believes the regulatory assets and liabilities created to offset the fair value adjustments meet the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. KU's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU also considered whether a separate fair value should be assigned to KU's rights to operate within its various electric service areas but concluded that these rights only provided the opportunity to earn a regulated return and barriers to market entry, which in management's judgment is not considered a separately identifiable intangible asset under applicable accounting guidance; rather, it is considered going-concern value, or goodwill.

See Note 2, Acquisition by PPL and Note 7, Goodwill and Intangible Assets, for further information.

<u>New Accounting Guidance</u>

Recent accounting pronouncements affecting KU are detailed in Note 1, Summary of Significant Accounting Policies.

Other Information

PPL’s Audit Committee has approved the audit fees and audit-related services. The audit-related services include services in connection with regulatory filings, reviews of offering documents and registration statements and internal control reviews.

Management's Report of Internal Controls Over Financial Reporting

Through December 31, 2010, the Company was not subject to the internal control and other requirements of the Sarbanes-Oxley Act of 2002 and associated rules (the "Act") and consequently is not required to evaluate the effectiveness of its internal control over financial reporting pursuant to Section 404 of the Act. However, management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process affected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework.* Management has concluded that, as of December 31, 2010, the Company's internal control over financial reporting was effective based on those criteria.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included herein.

Kentucky Utilities Company
Statements of Income
(millions)

	Successor	Predecessor		
	November 1 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31 2009	Year Ended December 31 2008
Operating revenues (Note 15)	$ 263	$ 1,248	$ 1,355	$ 1,405
Operating expenses:				
Fuel for electric generation	78	417	434	513
Power purchased (Notes 13 and 15)	28	147	199	221
Other operation and maintenance expenses	66	280	320	275
Depreciation and amortization	26	119	133	136
Total operating expenses	198	963	1,086	1,145
Operating income	65	285	269	260
Equity in earnings of unconsolidated venture (Note 1)	-	3	1	30
Interest expense (Notes 11 and 12)	8	6	6	14
Interest expense to affiliated companies (Notes 11, 12 and 15)	2	62	69	58
Other income (expense) - net	-	(2)	5	8
Income before income taxes	55	218	200	226
Income tax expense (Note 10)	20	78	67	68
Net income	$ 35	$ 140	$ 133	$ 158

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Retained Earnings
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Balance at beginning of period	$ 1,418	$ 1,328	$ 1,195	$ 1,037
Effect of PPL acquisition	(1,418)	-	-	-
Balance at November 1, 2010	-	1,328	1,195	1,037
Net income	35	140	133	158
Cash dividends declared (Note 15)	-	(50)	-	-
Balance at end of period	$ 35	$ 1,418	$ 1,328	$ 1,195

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Comprehensive Income
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Net income	$ 35	$ 140	$ 133	$ 158
Equity investee's other comprehensive loss, net of tax expense of $0, $1, $0 and $0, respectively (Note 1)	-	(2)	-	-
Comprehensive income	$ 35	$ 138	$ 133	$ 158

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets
(millions)

Assets	Successor December 31, 2010	Predecessor December 31, 2009
Current assets:		
Cash and cash equivalents	$ 3	$ 2
Accounts receivable (less allowance for doubtful accounts: 2010, $6; 2009, $3):		
Customer	90	79
Affiliated companies	12	9
Other	20	18
Unbilled revenues	89	76
Fuel, materials and supplies:		
Fuel (predominantly coal)	95	98
Other materials and supplies	41	39
Other intangible assets	22	-
Regulatory assets (Note 3)	9	32
Prepayments and other current assets	15	13
Total current assets	396	366
Investment in unconsolidated venture (Note 1)	30	12
Property, plant and equipment:		
Regulated utility plant – electric	3,630	4,892
Accumulated depreciation	(14)	(1,838)
Net regulated utility plant	3,616	3,054
Construction work in progress	955	1,257
Property, plant and equipment – net	4,571	4,311
Deferred debits and other assets:		
Regulatory assets (Notes 3 and 9):		
Pension benefits	117	105
Other regulatory assets	105	117
Goodwill (Notes 2 and 7)	607	-
Other intangibles assets (Notes 2 and 7)	175	-
Cash surrender value of key man life insurance	39	38
Other assets	19	7
Total deferred debits and other assets	1,062	267
Total assets	$ 6,059	$ 4,956

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (continued)
(millions)

Liabilities and Equity	Successor December 31, 2010	Predecessor December 31, 2009
Current liabilities:		
Current portion of long-term debt (Note 11)	$ -	$ 228
Current portion of long-term debt to affiliated company (Notes 11 and 15)	-	33
Notes payable to affiliated companies (Notes 12 and 15)	10	45
Accounts payable	67	107
Accounts payable to affiliated companies (Note 15)	45	88
Accrued taxes	25	14
Customer deposits	23	22
Regulatory liabilities (Note 3)	41	4
Accrued interest	8	1
Employee accruals	15	13
Other current liabilities	18	14
Total current liabilities	252	569
Long-term debt:		
Long-term bonds (Note 11)	1,841	123
Long-term debt to affiliated company (Notes 11 and 15)	-	1,298
Total long-term debt	1,841	1,421
Deferred credits and other liabilities:		
Deferred income taxes (Note 10)	376	336
Accumulated provision for pensions (Note 9)	113	160
Investment tax credits (Note 10)	104	104
Asset retirement obligations (Notes 3 and 4)	54	34
Regulatory liabilities (Note 3):		
Accumulated cost of removal of utility plant	348	335
Other regulatory liabilities	186	25
Other liabilities	94	20
Total deferred credits and other liabilities	$ 1,275	$ 1,014

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (continued)
(millions)

Equity:	Successor December 31, 2010	Predecessor December 31, 2009
Common stock, without par value – authorized 80,000,000 shares, outstanding 37,817,878 shares	$ 308	$ 308
Additional paid-in capital	2,348	316
Retained earnings:		
Retained earnings	35	1,318
Undistributed earnings from unconsolidated venture	-	10
Total equity	2,691	1,952
Total liabilities and equity	$ 6,059	$ 4,956

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Cash flows from operating activities:				
Net income	$ 35	$ 140	$ 133	$ 158
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Depreciation and amortization	26	119	133	136
Deferred income taxes – net	4	23	50	(13)
Investment tax credits (Note 10)	-	-	24	25
Provision for pension and postretirement benefits	5	13	26	10
Other – net	2	(3)	-	1
Change in current assets and liabilities:				
Accounts receivable	(15)	13	11	13
Unbilled revenues	(32)	19	(15)	(1)
Fuel, materials and supplies	5	(6)	(28)	(33)
Regulatory assets	(2)	19	-	-
Other current assets	9	(9)	(3)	(1)
Accounts payable	9	(17)	(32)	2
Accounts payable to affiliated companies	(41)	46	29	7
Accrued taxes	15	(5)	6	8
Regulatory liabilities	12	3	-	-
Other current liabilities	(2)	2	2	(3)
Pension and postretirement funding (Note 9)	(2)	(18)	(20)	(5)
Storm restoration regulatory asset (Note 3)	-	-	(57)	(2)
Other regulatory assets	1	8	-	-
Other regulatory liabilities	-	(10)	-	-
Other – net	(1)	7	(6)	(10)
Net cash provided by (used in) operating activities	28	344	253	292
Cash flows from investing activities:				
Construction expenditures	(87)	(292)	(516)	(686)
Purchases of assets from affiliate	-	(48)	-	(10)
Change in restricted cash	-	-	9	1
Net cash provided by (used in) investing activities	$ (87)	$ (340)	$ (507)	$ (695)

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company

Statements of Cash Flows (continued)

(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010,	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Cash flows from financing activities:				
Issuance of bonds (Note 11)	$ 1,489	$ -	$ -	$ 77
Short-term borrowings from affiliated company – net (Note 12)	(83)	48	29	(7)
Other borrowings from affiliated companies (Note 11)	1,331	-	150	250
Repayments on other borrowings from affiliated companies (Note 11)	(1,331)	-	-	-
Repayments to E.ON affiliate (Note 11)	(1,331)	-	-	-
Debt issuance costs	(17)	-	-	-
Retirement of pollution control bonds	-	-	-	(60)
Acquisition of outstanding bonds	-	-	-	(80)
Reissuance of reacquired bonds	-	-	-	63
Retirement of reacquired bonds	-	-	-	17
Payment of dividends	-	(50)	-	-
Capital contribution (Note 15)	-	-	75	145
Net cash provided by (used in) financing activities	58	(2)	254	405
Change in cash and cash equivalents	(1)	2	-	2
Cash and cash equivalents at beginning of period	4	2	2	-
Cash and cash equivalents at end of period	$ 3	$ 4	$ 2	$ 2
Supplemental disclosures of cash flow information:				
Cash paid (received) during the year for:				
Interest – net of amount capitalized	$ 22	$ 62	$ 70	$ 66
Income taxes – net	(12)	74	(9)	46

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Long-term debt (Note 11):		
Pollution control series:		
Mercer Co. 2000 Series A, due May 1, 2023, variable %	$ 13	$ 13
Carroll Co. 2007 Series A, due February 1, 2026, 5.75%	18	18
Carroll Co. 2002 Series A, due February 1, 2032, variable %	21	21
Carroll Co. 2002 Series B, due February 1, 2032, variable %	2	2
Muhlenberg Co. 2002 Series A, due February 1, 2032, variable %.	2	2
Mercer Co. 2002 Series A, due February 1, 2032, variable %	8	8
Carroll Co. 2008 Series A, due February 1, 2032, variable %	78	78
Carroll Co. 2002 Series C, due October 1, 2032, variable %	96	96
Carroll Co. 2006 Series B, due October 1, 2034, variable %	54	54
Trimble Co. 2007 Series A, due March 1, 2037, 6.0%	9	9
Carroll Co. 2004 Series A, due October 1, 2034, variable %	50	50
Total pollution control series	351	351
First mortgage bonds:		
First mortgage bond 2015 Series, due November 1, 2015, 1.625%	250	-
First mortgage bond 2020 Series, due November 1, 2020, 3.25%	500	-
First mortgage bond 2040 Series, due November 1, 2040, 5.125%	750	-
Total first mortgage bonds	$ 1,500	$ -

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization (continued)
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Long-term debt to affiliated company:		
Due November 24, 2010, 4.24%, unsecured	$ -	$ 33
Due January 16, 2012, 4.39%, unsecured	-	50
Due April 30, 2013, 4.55%, unsecured	-	100
Due August 15, 2013, 5.31%, unsecured	-	75
Due December 19, 2014, 5.45%, unsecured	-	100
Due July 8, 2015, 4.735%, unsecured	-	50
Due December 21, 2015, 5.36%, unsecured	-	75
Due October 25, 2016, 5.675%, unsecured	-	50
Due April 24, 2017, 5.28%, unsecured	-	50
Due June 20, 2017, 5.98%, unsecured	-	50
Due July 25, 2018, 6.16%, unsecured	-	50
Due August 27, 2018, 5.645%, unsecured	-	50
Due December 17, 2018, 7.035%, unsecured	-	75
Due July 29, 2019, 4.81%, unsecured	-	50
Due October 25, 2019, 5.71%, unsecured	-	70
Due November 25, 2019, 4.445%, unsecured	-	50
Due February 7, 2022, 5.69%, unsecured	-	53
Due May 22, 2023, 5.85%, unsecured	-	75
Due September 14, 2028, 5.96%, unsecured	-	100
Due June 23, 2036, 6.33%, unsecured	-	50
Due March 30, 2037, 5.86%, unsecured	-	75
Total long-term debt to affiliated company	-	1,331
Total long-term debt outstanding	1,851	1,682
Purchase accounting adjustments and discounts	(10)	-
Less current portion of long-term debt	-	261
Long-term debt	$ 1,841	$ 1,421

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization (continued)
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Common equity:		
Common stock, without par value – authorized 80,000,000 shares, outstanding 37,817,878 shares	$ 308	$ 308
Additional paid-in-capital	2,348	316
Retained earnings:		
Retained earnings	35	1,318
Undistributed subsidiary earnings	-	10
Total retained earnings	35	1,328
Total common equity	2,691	1,952
Total capitalization	$ 4,532	$ 3,373

The accompanying notes are an integral part of these financial statements.

Note 1 - Summary of Significant Accounting Policies

General

Terms and abbreviations are explained in the index of abbreviations. Dollars are in millions unless otherwise noted.

Business

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 514,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in five counties in southwestern Virginia and less than ten customers in Tennessee. KU's service area covers approximately 6,600 noncontiguous square miles. Approximately 98% of the electricity generated by KU is produced by its coal-fired electric generating stations. The remainder is generated by natural gas and oil fueled CTs and a hydroelectric power plant. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

On November 1, 2010, KU became an indirect wholly owned subsidiary of PPL, when PPL acquired all of the outstanding limited liability company interests in the Company's direct parent, LKE, from E.ON US Investments Corp. LKE, a Kentucky limited liability company, also owns the affiliate, LG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy and distribution and sale of natural gas in Kentucky. Following the acquisition, the Company's business has not changed. KU and LG&E are continuing as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies.

Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K.

Basis of Accounting

KU's basis of accounting incorporates the business combinations guidance of the FASB ASC as of the date of the acquisition, which requires the recognition and measurement of identifiable assets acquired and liabilities assumed at fair value as of the acquisition date. KU's financial statements and accompanying footnotes have been segregated to present pre-acquisition activity as the Predecessor and post-acquisition activity as the Successor. Predecessor covers the time period prior to November 1, 2010. Successor covers the time period after October 31, 2010. Certain accounting and presentation methods were changed to acceptable alternatives to conform to PPL accounting policies, which are discussed below, and the cost basis of certain assets and liabilities were changed as of November 1, 2010, as a result of the application of push-down accounting. Consequently, the financial position, results of operations and cash flows for the Predecessor period are not comparable to the Successor period.

Despite the separate presentation, the core operations of the Company have not changed. See Note 2, Acquisition by PPL, for information regarding the acquisition and the purchase accounting adjustments.

Changes in Classification

Certain reclassification entries have been made to the Predecessor's previous years' financial statements to conform to the 2010 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows. These reclassifications mainly consist of those necessary to identify amounts for prior periods that are separately disclosed in the financial statements.

Regulatory Accounting

KU is a cost-based rate-regulated utility. As a result, the financial statements reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise be charged to expense. Likewise, regulatory liabilities may be recognized for obligations expected to be returned through future regulated customer rates. The effect of such transactions or events would otherwise be reflected as income, or, in certain cases, regulatory liabilities are recorded based on the understanding with the regulator that current rates are being set to recover costs that are expected to be incurred in the future. The regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. Offsetting regulatory assets or liabilities for fair value purchase accounting adjustments have also been recorded to eliminate any ratemaking impact of the fair value adjustments. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC, Kentucky Commission, Virginia Commission or the Tennessee Regulatory Authority. See Note 3, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Management's Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported assets and liabilities, the disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Derivative Financial Instruments

KU enters into energy trading contracts to manage price risk and to maximize the value of power sales from the physical assets it owns. The energy trading contracts are non-hedging derivatives and the change in value is recognized in earnings on a mark-to-market basis. The Predecessor and Successor presentation are both appropriate under GAAP. The Predecessor and Successor determine the classification of energy trading contracts based on the settlement date of the individual contracts. Energy trading contracts classified as current are recognized in "Prepayments and other current assets" or "Other current liabilities" on the Balance Sheets. Energy trading contracts classified as non-current are recognized in "Other assets" or "Other liabilities" on the Balance Sheets. Cash inflows and outflows

related to derivative instruments are included as a component of operating activity on the Statements of Cash Flows, due to the underlying nature of the hedged items.

The Company does not net collateral against derivative instruments.

See Note 5, Derivative Financial Instruments, and Note 6, Fair Value Measurements, for further information on derivative instruments.

Revenue and Accounts Receivable

The operating revenues line item in the Statements of Income contains revenues from the following:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,	
			2009	2008
Residential	$ 106	$ 440	$ 480	$ 462
Industrial and commercial	117	588	637	636
Municipals	15	88	91	92
Other retail	20	114	118	108
Wholesale	5	18	29	107
	$ 263	$ 1,248	$ 1,355	$ 1,405

Revenue Recognition

Revenues are recorded based on service rendered to customers through month-end. Operating revenues are recorded based on energy deliveries through the end of the calendar month. Unbilled retail revenues result because customers' meters are read and bills are rendered throughout the month, rather than all being read at the end of the month. Unbilled revenues for a month are calculated by multiplying an estimate of unbilled kWh by the estimated average cents per kWh.

Accounts Receivable

Accounts receivable are reported in the Balance Sheets at the gross outstanding amount adjusted for an allowance for doubtful accounts.

Allowance for Doubtful Accounts

The allowance for doubtful accounts included in "Accounts receivable – customer" is based on the ratio of the amounts charged-off during the last twelve months to the retail revenues billed over the same period, multiplied by the retail revenues billed over the last four months. Accounts with no payment activity are charged-off after four months, although collection efforts continue thereafter. The allowance for doubtful accounts included in "Accounts receivable – other" is composed of accounts aged more than four months. Accounts are written off as management determines them uncollectible.

The changes in the allowance for doubtful accounts were:

	Successor	Predecessor		
	December 31, 2010	October 31, 2010	December 31, 2009	December 31, 2008
Balance at beginning of period (a)	$ -	$ 3	$ 3	$ 2
Charged to income	1	(6)	(4)	(2)
Charged to balance sheets	5	6	4	3
Balance at end of period	$ 6	$ 3	$ 3	$ 3

(a) Successor beginning of period reflects revaluation of accounts receivable due to purchase accounting.

Cash

Cash Equivalents

All highly liquid investments with an original maturity of three months or less are considered to be cash equivalents.

Restricted Cash

Bank deposits and other cash equivalents that are restricted by agreement or that have been clearly designated for a specific purpose are classified as restricted cash. The change in restricted cash is reported as an investing activity on the Statements of Cash Flows. On the Balance Sheets, restricted cash is included in “Prepayments and other current assets”. For KU, the December 31, 2010, balance of restricted cash was less than $1 million.

Fair Value Measurements

KU values certain financial assets and liabilities at fair value. Generally, the most significant fair value measurements relate to derivative assets and liabilities, investments in securities including investments in the pension and postretirement benefit plans and cash and cash equivalents. KU uses, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques) and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions that market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

KU prioritizes fair value measurements for disclosure by grouping them into one of three levels in the fair value hierarchy. The highest priority is given to measurements using level 1 inputs. The appropriate level assigned to a fair value measurement is based on the lowest level input that is significant to the fair value measurement in its entirety. The three levels of the fair value hierarchy are as follows:

- Level 1 - Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - Other inputs that are directly or indirectly observable in the marketplace.
- Level 3 - Unobservable inputs which are supported by little or no market activity.

Assessing the significance of a particular input requires judgment that considers factors specific to the asset or liability. As such, KU's assessment of the significance of a particular input may affect how the assets and liabilities are classified within the fair value hierarchy. See Note 5, Derivatives Financial Instruments, and Note 6, Fair Value Measurements, for further information on fair value measurements.

Investments

Equity Method Investment

KU's equity method investment, included in "Investment in unconsolidated venture" on the Balance Sheets, consists of its investment in EEI. KU owns 20% of the common stock of EEI, which owns and operates a 1,002 Mw summer capacity coal-fired plant and a 74 Mw summer capacity natural gas facility in southern Illinois. Through a power marketer affiliated with its majority owner, EEI sells its output to third parties. Although KU holds investment interest in EEI, it is not the primary beneficiary and is therefore not consolidated into the Company's financial statements. KU's investment in EEI is accounted for under the equity method of accounting and as of December 31, 2010 and 2009, totaled $30 million and $12 million, respectively. KU's direct exposure to loss as a result of its involvement with EEI is generally limited to the value of its investment. See Note 2, Acquisition by PPL, for further discussion regarding purchase accounting adjustments recognized for KU's investment in EEI.

The results of operations and financial position of EEI, KU's equity method investment, are summarized below.

Condensed income statement information for the years ended December 31 is as follows:

	2010 (unaudited)	2009	2008
Net sales	$ 343	$ 297	$ 514
Net income	16	10	142
KU's equity in earnings of EEI	3	1	30

Condensed balance sheet information as of December 31 is as follows:

	2010 (unaudited)	2009
Current assets	$ 62	$ 84
Long-lived assets	181	178
Total assets	$ 243	$ 262
Current liabilities	$ 113	$ 166
Long-term liabilities	72	50
Equity	58	46
Total liabilities and equity	$ 243	$ 262

Cost Method Investment

KU's cost method investment, included in "Investments in unconsolidated venture" on the Balance Sheets, consists of the Company's investment in OVEC. KU and 11 other electric utilities are owners of OVEC, which is located in Piketon, Ohio. OVEC owns and operates two coal-fired power plants, Kyger Creek Station in Ohio and Clifty Creek Station in Indiana with combined nameplate generating capacities of 2,390 Mw. OVEC's power is currently supplied to KU and 13 other companies affiliated with the various owners. Pursuant to current contractual agreements, KU owns 2.5% of OVEC's common stock and is contractually entitled to 2.5% of OVEC's output. Based on nameplate generating capacity, this would be approximately 60 Mw.

As of December 31, 2010 and 2009, KU's investment in OVEC totaled less than $1 million. KU is not the primary beneficiary of OVEC; therefore, it is not consolidated into the Company's financial statements and is accounted for under the cost method of accounting. The direct exposure to loss as a result of the Company's involvement with OVEC is generally limited to the value of its investment; however, KU may be conditionally responsible for a pro-rata share of certain OVEC obligations. See Note 2, Acquisition by PPL, and Note 13, Commitments and Contingencies, for further discussion regarding purchase accounting adjustments recognized, and KU's ownership interest and power purchase rights.

Long-Lived and Intangible Assets

Regulated Utility Plant

Regulated utility plant was stated at original cost for the Predecessor and adjusted to the net book value on November 1, 2010, the acquisition date, for the Successor. KU determined that fair value was equal to net book value at the acquisition date since KU's operations are conducted in a regulated environment. Original cost includes payroll-related costs such as taxes, fringe benefits and administrative and general costs. Construction work in progress has been included in the rate base for determining retail customer rates. KU has not recorded significant allowance for funds used during construction in accordance with FERC.

The cost of plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost is charged to the reserve for depreciation. When complete operating units are disposed of,

appropriate adjustments are made to the reserve for depreciation and gains and losses, if any, are recognized.

Capitalized Software Cost

Included in "Property, plant and equipment" on the Balance Sheets are capitalized costs of software projects that were developed or obtained for internal use. These capitalized costs are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Following are capitalized software costs and the accumulated amortization:

Successor		Predecessor	
December 31, 2010		December 31, 2009	
Carrying Amount	Accumulated Amortization (a)	Carrying Amount	Accumulated Amortization
$ 40	$ 1	$ 52	$ 13

(a) The accumulated amortization as of November 1, 2010, was netted against the carrying amount of the software as the fair value was determined to be equal to net book value for property, plant and equipment.

Amortization expense of capitalized software costs was as follows:

Successor	Predecessor		
November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,	
		2009	2008
$ 1	$ 6	$ 6	$ 5

The amortization of capitalized software is included in "Depreciation and amortization" on the Statements of Income.

Depreciation and Amortization

Depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. The amounts provided as a percentage of depreciable plant were approximately:

Year	Percentage
2010	4.1%
2009	2.6%
2008	3.0%

Of the amount provided for depreciation, the following were related to the retirement, removal and disposal costs of long lived assets:

Year	Percentage
2010	0.6%
2009	0.4%
2008	0.5%

Goodwill, Intangible Assets and Asset Impairment

KU performs a quarterly review to determine if an impairment analyses is required for long-lived assets that are subject to depreciation or amortization. This review identifies changes in circumstances indicating that a long-lived asset's carrying value may not be recoverable. An impairment analysis will be performed if warranted, based on the review.

For a long-lived asset to be held and used, impairment exists when the carrying amount exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset is impaired, an impairment loss is recorded to adjust the asset's carrying amount to its fair value.

KU, as the result of PPL's acquisition of LKE, recorded the fair value of its coal contracts, emission allowances, EEI investment and OVEC power purchase contract. The difference between the fair value and the cost for these assets is being amortized over their useful lives based upon the pattern in which the economic benefits of the intangible assets are consumed or otherwise used. When determining the useful life of an intangible asset, including intangible assets that are renewed or extended, KU considers the expected use of the asset, the expected useful life of other assets to which the useful life of the intangible asset may relate and legal, regulatory, or contractual provisions that may limit the useful life. See Note 2, Acquisition by PPL, for methods used to determine the long-lived intangible assets' fair values. See Note 7, Goodwill and Intangible Assets, for the fair value amounts and amortization periods. The current intangible assets and long-term intangible assets are included in "Other intangible assets" on the Balance Sheets.

The Predecessor reported emission allowances in "Other materials and supplies" on the Balance Sheets. The emission allowances were not amortized; rather, they were expensed when consumed. The Predecessor did not recognize the coal contracts or the OVEC power purchase contract as these intangible assets were not derivatives.

In connection with PPL's acquisition of LKE, KU recorded goodwill on November 1, 2010. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is tested annually for impairment during the fourth quarter and more frequently if management determines that a triggering event may have occurred that would more likely than not reduce the fair value of an operating unit below its carrying value. Goodwill impairment charges are not subject to rate recovery. See Note 7, Goodwill and Intangible Assets, for further discussion regarding the Company's goodwill and current test results.

Asset Retirement Obligations

KU recognizes various legal obligations associated with the retirement of long-lived assets as liabilities in the financial statements. Initially this obligation is measured at fair value. An equivalent amount is recorded as an increase in the value of the capitalized asset and allocated to expense over the useful life of the asset. Until the obligation is settled, the liability is increased, through the recognition of accretion expense in the Statements of Income, for changes in the obligation due to the passage of time. An offsetting regulatory asset is recognized to reverse the depreciation and accretion expense related to the ARO such that there is no income statement impact. The regulatory asset is relieved when the ARO has been settled. Estimated ARO costs and settlement dates, which affect the carrying value of various AROs and the related assets, are reviewed periodically to ensure that any material changes are incorporated into the latest estimate of the obligations. See Note 4, Asset Retirement Obligations, for further information on AROs.

Defined Benefits

KU employees benefit from both funded and unfunded retirement benefit plans. An asset or liability is recorded to recognize the funded status of all defined benefit plans with an offsetting entry to regulatory assets or regulatory liabilities. Consequently, the funded status of all defined benefit plans is fully recognized on the Balance Sheets.

The expected return on plan assets is determined based on the current level of expected return on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class is then weighted based on the current asset allocation.

The discount rate used for pensions, postretirement and post-employment plans by the Predecessor was determined using the Mercer Yield Curve. The expected return on assets assumption was 7.75%. Gains and losses in excess of 10% of the greater of the plan's projected benefit obligation or market value of assets were amortized on a straight-line basis over the average future service period of active participants. The market-related value of assets was equal to the fair market value of the assets.

The discount rate used by the Successor was determined by the Towers Watson Yield Curve based on the individual plan cash flows. The expected return on assets was reduced from 7.75% to 7.25%. The amortization period for the recognition of gains and losses for retirement plans was changed to reflect the Successor's amortization policy. Under the Successor's method, gains and losses in excess of 10% but less than 30% of the greater of the plan's projected benefit obligation or market-related value of assets, are amortized on a straight-line basis over the average future service period of active participants. Gains and losses in excess of 30% of the plan's projected benefit obligation or market-related value of assets are amortized on a straight-line basis over a period equal to one-half of the average future service period of active participants. The market-related value of assets for the qualified retirement plans will be equal to a five year smoothed asset value. Gains and losses in excess of the expected return will be phased-in over a five-year period, prospectively from November 1, 2010.

See Note 9, Pension and Other Postretirement Benefit Plans, for further information.

Other

Loss Accruals

Potential losses are accrued when information is available that indicates it is “probable” that a loss has been incurred, given the likelihood of uncertain future events, and the amount of the loss can be reasonably estimated. Accounting guidance defines “probable” as cases in which “the future event or events are likely to occur.” KU continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events.

KU does not record the accrual of contingencies that might result in gains unless recovery is assured.

Income Taxes

For the periods ended on or before October 31, 2010, KU was a subsidiary of E.ON U.S. and was part of E.ON U.S.’s direct parent’s, E.ON US Investments Corp., consolidated U.S. federal income tax return. On November 1, 2010, KU became a part of PPL’s consolidated U.S. federal income tax return.

Significant management judgment is required in developing KU’s provision for income taxes primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and the determination of deferred tax assets, liabilities and valuation allowances.

KU evaluates tax positions following a two-step process. The first step requires an entity to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires an entity to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact the financial statements of KU.

Deferred income taxes reflect the net future tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes, as well as the tax effects of net operating losses and tax credit carryforwards.

KU records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. KU considers the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies in initially recording and subsequently reevaluating the need for valuation allowances. If KU determines that it is able to realize deferred tax assets in the future in excess of recorded net deferred tax assets, adjustments to the valuation allowances increase income by reducing tax expense in the period that such determination is made. Likewise, if KU determines that it is not able to realize all or part of net deferred tax assets in the future, adjustments to the valuation allowances would decrease income by increasing tax expense in the period that such determination is made.

The provision for KU's deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the regulators. The difference in the provision for deferred income taxes for regulated assets and liabilities and the amount that otherwise would be recorded under GAAP is deferred and included on the Balance Sheets in "Regulatory liabilities".

KU defers investment tax credits when the credits are utilized and amortizes the deferred amounts over the average lives of the related assets.

See Note 10, Income Taxes, for further discussion regarding income taxes.

Leases

KU evaluates whether arrangements entered into contain leases for accounting purposes.

Materials and Supplies

Fuel and other materials and supplies inventories are accounted for using the average-cost method.

Fuel Costs

The cost of fuel for electric generation is charged to expense as used. See Note 3, Rates and Regulatory Matters, for a description of the FAC.

Debt

The Company's long-term debt includes $228 million of pollution control bonds, which are subject to tender for purchase at the option of the holder and to mandatory tender for purchase on the occurrence of certain events. The Successor has classified these bonds as long term because the Company has the intent and ability to utilize its $400 million credit facility, which matures in December 2014, to fund any mandatory purchases. Predecessor classified these bonds as current portion of long-term debt due to the tender for purchase provisions. The Predecessor presentation and the Successor presentation are both appropriate under GAAP. See Note 11, Long-Term Debt, and Note 12, Notes Payable and Other Short-Term Obligations, for more information on the Company's debt and credit facilities.

Unamortized Debt Expense

Debt expense is capitalized and amortized over the lives of the related bond issues using the straight line method, which approximates the effective interest method. Depending on the type of expense, the Successor capitalized debt expenses in long-term other regulatory assets or long-term other assets to align with the term of the debt the expenses were related. The Predecessor capitalized debt expenses in current or long-term other regulatory assets or other current or long-term other assets based on the amount of expense expected to be recovered within the next year through rate recovery. Both the Predecessor and the Successor amortize debt expenses over the lives of the related bond issues. The Predecessor presentation and the Successor presentation are both appropriate under regulatory practices and GAAP.

Recent Accounting Pronouncements

The following recent accounting pronouncement affected KU:

Fair Value Measurements

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances and settlements within level 3 measurements. This guidance is effective for the interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about the roll-forward of activity in level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. This guidance has no impact on the Company's results of operations, financial position, liquidity or disclosures.

Note 2 - Acquisition by PPL

On November 1, 2010, PPL completed its acquisition of LKE and its subsidiaries. The push-down basis of accounting was used to record the fair value adjustments of assets and liabilities on LKE at the acquisition date. PPL paid a cash consideration for LKE and its subsidiaries of $2,493 million as well as a capital contribution on November 1, 2010, of $1,565 million; included within this was the consideration paid for KU of $2,656 million. The allocation of the KU purchase price was based on the fair value of assets acquired and liabilities assumed.

The allocation of the purchase price to the fair value of assets acquired and liabilities assumed is as follows:

Current assets	$	364
Investments		30
Property, plant and equipment		4,531
Other intangible assets		178
Regulatory and other non-current assets		274
Current liabilities (excluding current portion of long-term debt)		(367)
Affiliated debt		(1,331)
Debt (current and non-current)		(352)
Other non-current liabilities		(1,278)
Net identifiable assets acquired		2,049
Goodwill		607
Total purchase price	$	2,656

Goodwill represents value paid for the rate regulated business of KU, which is located in a defined service area with a constructive regulatory environment, which provides for future investment, earnings and cash flow growth, as well as the talented and experienced workforce. KU's franchise values are being attributed to the going concern value of the business, and thus were recorded as goodwill rather than a separately identifiable intangible asset. None of the goodwill recognized is deductible for income tax purposes or included in regulated customer rates.

Adjustments to KU's assets and liabilities that contributed to goodwill were as follows:

The fair value adjustment on the EEI investment was calculated using the discounted cash flow valuation method. The result was an increase in KU's value of the investment in EEI; the fair value of EEI was calculated to be $30 million and a fair value adjustment of $18 million was recorded on KU. The fair value adjustment to EEI is amortized over the expected remaining useful life of plant and equipment at EEI, which is estimated to be over 20 years.

The pollution control bonds on KU had a fair value adjustment of $1 million. All variable bonds were valued at par while the fixed rate bonds were valued with a yield curve based on average credit spreads for similar bonds.

As a result of the purchase accounting associated with the acquisition, the following items had a fair value adjustment but no effect on goodwill as the offset was either a regulatory asset or liability. The regulatory asset or liability has been recorded to eliminate any ratemaking impact of the fair value adjustments:

- The value of OVEC was determined to be $39 million based upon an announced transaction by another owner. KU's stock was valued at less than $1 million and the power purchase agreement has been valued at $39 million. An intangible asset was recorded with the offset to regulatory liability and will be amortized using the units of production method until the power purchase agreement ends in March 2026.
- KU recorded an emission allowance intangible asset and regulatory liability as the result of adjusting the fair value of the emission allowances at KU. The emission allowance intangible of $9 million represents allocated and purchased SO_2 and NOx emission allowances that are unused as of the valuation date or allocated for use in future years. KU had previously recorded emission allowances as other materials and supplies. To conform to PPL's accounting policy all emission allowances are now recorded as intangible assets. The emission allowance intangible asset is amortized as the emission allowances are consumed, which is expected to occur through 2040.
- KU recorded a coal contract intangible asset of $145 million and non-current liability of $22 million on the Balance Sheets. An offsetting regulatory asset was recorded for those contracts with unfavorable terms relative to market. An offsetting regulatory liability was recorded for those contracts that had favorable terms relative to market. All coal contracts held by KU, wherein it had entered into arrangements to buy amounts of coal at fixed prices from counterparties at a future date, were fair valued. The intangible assets and other liabilities, as well as the regulatory assets and liabilities, are being amortized over the same terms as the related contracts, which expire through 2016.

The fair value of intangible assets and liabilities (e.g. contracts that have favorable or unfavorable terms relative to market), including coal contracts and power purchase agreements, as well as emission allowances, have been reflected on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the acquisition. As a result, management believes the regulatory assets and liabilities created to offset the fair value adjustments meet the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair

value adjustments. KU’s customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU also considered whether a separate fair value should be assigned to KU’s rights to operate within its various electric service areas but concluded that these rights only provided the opportunity to earn a regulated return and barriers to market entry, which in management’s judgment is not considered a separately identifiable intangible asset under applicable accounting guidance; rather, it is considered going-concern value, or goodwill.

Note 3 - Rates and Regulatory Matters

The Company is subject to the jurisdiction of the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority in virtually all matters related to electric utility regulation and as such, its accounting is subject to the regulated operations guidance of the FASB ASC. Given its position in the marketplace and the status of regulation in Kentucky and Virginia, there are no plans or intentions to discontinue the application of the regulated operations guidance of the FASB ASC.

KU’s Kentucky base rates are calculated based on a return on capitalization (common equity, long-term debt and notes payable) including certain regulatory adjustments to exclude non-regulated investments and environmental compliance plans recovered separately through the ECR mechanism. No regulatory assets or regulatory liabilities recorded at the time base rates were determined were excluded from the return on capitalization utilized in the calculation of Kentucky base rates. Therefore, a return is earned on all Kentucky regulatory assets existing at the time base rates were determined, except where such regulatory assets were offset by associated liabilities and thus, have no net impact on capitalization.

As a result of purchase accounting, certain fair value amounts, reflecting contracts that have favorable or unfavorable terms relative to market, were recorded on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered in customer rates the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. KU’s customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU’s Virginia base rates are calculated based on a return on rate base. All regulatory assets and liabilities are excluded from the return on rate base utilized in the calculation of Virginia base rates.

KU’s wholesale requirements rates for municipal customers are calculated based on annual updates to a rate formula that utilizes a return on rate base. All regulatory assets and liabilities are excluded from the return on rate base utilized in the development of municipal rates.

<u>2010 Purchase and Sale Agreement with PPL</u>

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the “Agreement”) had been entered into among E.ON US Investments Corp., PPL and E.ON.

The transaction was subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals

(including the FERC and state regulators in Kentucky, Virginia and Tennessee) and the absence of injunctions or restraints imposed by governmental entities.

Change of control and financing-related applications were filed on May 28, 2010 with the Kentucky Commission and on June 15, 2010 with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings and data request filings and responses occurred. Early termination of the Hart-Scott-Rodino waiting period was received on August 2, 2010.

A hearing in the Kentucky Commission proceedings was held on September 8, 2010 at which time a unanimous settlement agreement was presented. In the settlement, KU committed that no base rate increases would take effect before January 1, 2013. The KU rate increases that took effect on August 1, 2010, were not impacted by the settlement. Under the terms of the settlement, KU retains the right to seek approval for the deferral of “extraordinary and uncontrollable costs.” Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and demand-side management cost trackers. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Utilities file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits KU to earn up to a 10.75% return on equity. Any earnings above a 10.75% return on equity will be shared with customers on a 50%/50% basis. On September 30, 2010, the Kentucky Commission issued an Order approving the transfer of ownership of KU via the acquisition of E.ON U.S. by PPL, incorporating the terms of the submitted settlement. On October 19, 2010 and October 21, 2010, respectively, Orders approving the acquisition of E.ON U.S. by PPL were received from the Virginia Commission and the Tennessee Regulatory Authority. The Commissions’ Orders contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In mid-September 2010, KU and other applicants in the FERC change of control proceeding reached an agreement with the protesters, whereby such protests have been withdrawn. The agreement, which was filed for consideration with the FERC, includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an agreement not to terminate certain KU municipal customer contracts prior to January 2017, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that KU has agreed not to seek the same transaction-related costs from retail customers and agreements to coordinate with protesters in certain open or ongoing matters. A FERC Order approving the transaction was received on October 26, 2010 and the transaction was completed November 1, 2010.

2010 Kentucky Rate Case

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $135 million annually. In June 2010, KU and all of the intervenors, except the AG, agreed to stipulations providing for an increase in electric base rates of $98 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulations, including a return on equity range of 9.75 – 10.75%. The new rates became effective on August 1, 2010.

Virginia Rate Case

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based on a return on equity of 12%. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing base rate revenue increases of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU refunded $1 million in interim rate amounts in excess of the ultimate approved rates.

FERC Wholesale Rate Case

In September 2008, KU filed an application with the FERC for increases in electric base rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from an all-in stated unit charge rate to an unbundled formula rate, including an annual adjustment mechanism. In 2009, the FERC issued an Order approving a settlement among the parties in the case, incorporating increases of approximately 3% from prior rates and a return on equity of 11%. In May 2010, KU submitted to the FERC the proposed current annual adjustments to the formula rates which incorporated certain proposed increases. Updated rates, including certain further adjustments from a review process involving wholesale requirements customers, became effective as of July 1, 2010, subject to certain review procedures by the wholesale requirements customers and the FERC.

By mutual agreement, the parties' settlement of the 2008 application left outstanding the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. An Order was issued by the FERC in July 2010, indicating that KU is not required to allocate a portion of any renewable resources to the twelve municipalities, thus resolving the remaining issue.

2008 Kentucky Rate Case

In July 2008, KU filed an application with the Kentucky Commission requesting an increase in electric base rates. In January 2009, KU, the AG, the KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which KU's electric base rates decreased by $9 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in the Balance Sheets as of December 31:

	Successor 2010	Predecessor 2009
Current regulatory assets:		
ECR (a)	$ -	$ 28
FAC (a)	-	1
Coal contracts (b)	4	-
MISO exit (c)	-	2
Other (d)	5	1
Total current regulatory assets	$ 9	$ 32
Non-current regulatory assets:		
Pension and postretirement benefits (e)	$ 117	$ 105
Other non-current regulatory assets:		
Storm restoration (c)	57	59
ARO (f)	2	30
Unamortized loss on bonds (c)	12	12
Coal contracts (b)	14	-
MISO exit (a)	5	9
Unamortized debt expense	5	-
Other (d)	10	7
Subtotal other non-current regulatory assets	105	117
Total non-current regulatory assets	$ 222	$ 222
Current regulatory liabilities:		
Coal contracts	$ 16	$ -
ECR	12	-
FAC	2	-
DSM	5	3
Emission allowances	6	-
Other (g)	-	1
Total current regulatory liabilities	$ 41	$ 4
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$ 348	$ 335
Other non-current regulatory liabilities:		
Coal contracts	126	-
OVEC power purchase contract	38	-
Deferred income taxes – net	6	9
Postretirement benefits	10	9
Other (g)	6	7
Subtotal other non-current regulatory liabilities	186	25
Total non-current regulatory liabilities	$ 534	$ 360

(a) The FAC and ECR regulatory assets have separate recovery mechanisms with recovery within twelve months.
(b) Offsetting regulatory asset for fair value purchase accounting adjustments. See Note 2, Acquisition by PPL, for information on the purchase accounting adjustments.
(c) These regulatory assets are recovered through base rates.
(d) Other regulatory assets include:
    - The CMRG and KCCS contributions, an EKPC FERC transmission settlement agreement and rate case expenses, which are recovered through base rates.
    - The FERC jurisdictional portion of the EKPC FERC transmission settlement agreement included in current and non-current regulatory assets, recovered through the application of the annual OATT formula rate updates.
    - FERC jurisdictional pension expense, which will be requested in a future FERC rate case.
    - Offsetting regulatory asset for fair value purchase accounting adjustment for leases. See Note 2, Acquisition by PPL, for information on the purchase accounting adjustments.
    - The Virginia levelized fuel factor, which is a separate recovery mechanism with recovery within twelve months.
(e) KU generally recovers this asset through pension expense included in the calculation of base rates.
(f) When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability.
(g) Other regulatory liabilities includes the emission allowance purchase accounting offset, MISO exit and a change in accounting method for FERC jurisdictional spare parts.

ECR

KU recovers the costs of complying with the Federal Clean Air Act pursuant to Kentucky Revised Statute 278-183 as amended and those federal, state or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal, through the ECR mechanism. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

The Kentucky Commission requires reviews of the past operations of the environmental surcharge for six-month and two-year billing periods to evaluate the related charges, credits and rates of return, as well as to provide for the roll-in of ECR amounts to base rates each two-year period. In December 2010, the Kentucky Commission initiated a six-month review of the Utilities' environmental surcharge for the billing period ending October 2010. An order is expected in the second quarter of 2011. Also, in December 2010, an Order was issued approving the charges and credits billed through the ECR during the six-month period ending April 2010, as well as approving billing adjustments for under-recovered costs and the rate of return on capital. In May 2010, an Order was issued approving the amounts billed through the ECR during the six-month period ending October 2009, and the rate of return on capital and allowing recovery of the under-recovery position in subsequent monthly filings. In December 2009, an Order was issued approving the charges and credits billed through the ECR during the two-year period ending April 2009, an increase in the jurisdictional revenue requirement, a base rate roll-in and a revised rate of return on capital. In July 2009, an Order was issued approving the charges and credits billed through the ECR during the six-month period ending October 2008, as well as approving billing adjustments for under-recovered costs and the rate of return on capital. In August 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month periods ending April

2008 and October 2007, and the rate of return on capital. In March 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month and two-year periods ending October 2006 and April 2007, respectively, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. During 2009, KU reached a unanimous settlement with all parties to the case and the Kentucky Commission issued an Order approving KU's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle. At December 31, 2009, the Company had a regulatory asset of $28 million, which changed to a regulatory liability in the first quarter of 2010, as a result of these roll-in adjustments to base rates. At December 31, 2010, the regulatory liability balance was $12 million.

In February 2009, the Kentucky Commission approved a settlement agreement in the rate case which provides for an authorized return on equity applicable to the ECR mechanism of 10.63% effective with the February 2009 expense month filing, which represents a slight increase over the previously authorized 10.50%. The 10.63% return on equity for the ECR mechanism was affirmed in the 2010 rate case.

FAC

KU's retail rates contain an FAC, whereby increases and decreases in the cost of fuel for generation are reflected in the rates charged to retail customers. The FAC allows the Company to adjust billed amounts for the difference between the fuel cost component of base rates and the actual fuel cost, including transportation costs. Refunds to customers occur if the actual costs are below the embedded cost component. Additional charges to customers occur if the actual costs exceed the embedded cost component. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

The Kentucky Commission requires public hearings at six-month intervals to examine past fuel adjustments and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges. In December 2010, May 2010, November 2009, January 2009, June 2008 and January 2008, the Kentucky Commission issued Orders approving the charges and credits billed through the FAC for the six-month periods ending April 2010, August 2009, April 2009, April 2008, October 2007 and April 2007, respectively. In January 2009 the Kentucky Commission initiated routine examinations of the FAC for the two-year periods November 1, 2006 through October 31, 2008. The Kentucky Commission issued an Order in June 2009 approving the charges and credits billed through the FAC during the review periods.

KU also employs an FAC mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The Virginia levelized fuel factor allows fuel recovery based on projected fuel costs for the coming year plus an adjustment for any over- or under-recovery of fuel expenses from the prior year. At December 31, 2010 and 2009, KU had a regulatory asset of $5 million and less than $1 million, respectively.

In February 2010, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor beginning with service rendered in April 2010. An Order was issued in April 2010, resulting in an agreed upon decrease of 23% from the fuel factor in effect for April 2009 through March 2010.

In February 2009, KU filed an application with the Virginia Commission seeking approval of a 29% increase in its fuel cost factor beginning with service rendered in April 2009. In February 2009, the Virginia Commission issued an Order allowing the requested change to become effective on an interim basis. The Virginia Staff testimony filed in April 2009 recommended a slight decrease in the factor filed by KU. The Company indicated the Virginia Staff proposal was acceptable. A hearing was held in May 2009, with general resolution of remaining issues. In May 2009, the Virginia Commission issued an Order approving the revised fuel factor, representing an increase of 24%, effective May 2009.

In February 2008, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor applicable during the billing period, April 2008 through March 2009. The Virginia Commission allowed the new rates to be in effect for the April 2008 customer billings. In April 2008, the Virginia Commission Staff recommended a change to the fuel factor KU filed in its application, to which KU agreed. Following a public hearing and an Order in May 2008, the recommended change became effective in June 2008, resulting in a decrease of 0.482 cents/kWh from the factor in effect for the April 2007 through March 2008 period.

Coal Contracts

In November 2010, purchase accounting adjustments were recorded for the fair value of KU's coal contracts. Offsetting regulatory asset or liability for fair value purchase accounting adjustments eliminate any ratemaking impact of the fair value adjustments.

MISO

Following receipt of applicable FERC, Kentucky Commission and other regulatory Orders, related to proceedings that had been underway since July 2003, KU withdrew from the MISO effective September 1, 2006. Since the exit from the MISO, KU has been operating under a FERC approved OATT. KU now contracts with the TVA to act as its transmission reliability coordinator and SPP to function as its independent transmission operator, pursuant to FERC requirements. The contractual obligations with the TVA extend through August 2011 and with SPP through August 2012.

KU and the MISO agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, the Company paid $20 million to the MISO and made related FERC compliance filings. The Company's payment of this exit fee was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. KU and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee and the approved agreement providing KU with recovery of $4 million, of which $1 million was immediately recovered in 2008, with the remainder to be recovered over the seven years from 2008 through 2014 for credits realized from other payments the MISO will receive, plus interest.

In accordance with Kentucky Commission Orders approving the MISO exit, KU established a regulatory asset for the MISO exit fee, net of former MISO administrative charges collected via base rates through the base rate case test year ended April 30, 2008. The net MISO exit fee is subject to adjustment for possible future MISO credits and a regulatory liability for certain revenues associated with former MISO administrative charges, which were collected via base rates until February 6, 2009. The approved 2008 base rate case settlement provided for MISO administrative charges collected through base rates from May 1, 2008 to February 6, 2009, and any future adjustments to the MISO exit fee, to be established as a regulatory liability until the amounts can be amortized in future base rate cases. This regulatory liability balance as of October 31, 2009, was included in the base rate case application filed on January 29, 2010. MISO exit fee credit amounts subsequent to October 31, 2009, will continue to accumulate as a regulatory liability until they can be amortized in future base rate cases.

In November 2008, the FERC issued Orders in industry-wide proceedings relating to MISO RSG calculation and resettlement procedures. RSG charges are amounts assessed to various participants active in the MISO trading market which generally seek to compensate for uneconomic generation dispatch due to regional transmission or power market operational considerations, with some customer classes eligible for payments, while others may bear charges. The FERC Orders approved two requests for significantly altered formulas and principles, each of which the FERC applied differently to calculate RSG charges for various historical and future periods. Based upon the 2008 FERC Orders, the Company established a reserve during the fourth quarter of 2008 of less than $1 million relating to potential RSG resettlement costs for the period ended December 31, 2008. However, in May 2009, after a portion of the resettlement payments had been made, the FERC issued an Order on the requests for rehearing on one November 2008 Order which changed the effective date and reduced almost all of the previously accrued RSG resettlement costs. Therefore, these costs were reversed and a receivable was established for amounts already paid of less than $1 million. The MISO began refunding the amounts to the Company in June 2009 with full repayment by September 2009. In June 2009, the FERC issued an Order in the rate mismatch RSG proceeding, stating it will not require resettlements of the rate mismatch calculation from April 1, 2005 to November 4, 2007. An accrual had previously been recorded in 2008 for the rate mismatch issue for the time period April 25, 2006 to August 9, 2007, but no accrual had been recorded for the time period November 5, 2007 to November 9, 2008 based on the prior Order. Accordingly, the accrual for the former time period was reversed and an accrual for the latter time period was recorded in June 2009, with a net effect of $1 million of expense, substantially all of which was paid by September 2009.

In August 2009, the FERC determined that the MISO had failed to demonstrate that its proposed exemptions to real-time RSG charges were just and reasonable. In November 2009, the MISO made a compliance filing incorporating the rulings of the FERC Orders and a related task force, with a primary open issue being whether certain of the tariff changes are applied prospectively only or retroactively to approximately January 6, 2009.

In November 2009, the Utilities filed an application with the FERC to approve certain independent transmission operator arrangements to be effective upon the expiration of their current contract with SPP in September 2010. The application sought authority for KU and LG&E to function after such date as the administrators of their own OATT for most purposes. However, due to the lack of FERC approval for such an approach and the approaching expiration of the SPP contract, the Utilities determined the approach was no longer reasonably achievable without unacceptable delay and uncertainty. In July 2010, the Utilities entered into a new agreement with SPP to provide independent transmission operator

services for a specified, limited time and removed its application for authority of administering its own OATT. The TVA, which currently acts as reliability coordinator, has also been retained under the existing service contract. The new agreement extends TVA services to August 2011 with no alterations or changes to the party's duties or responsibilities.

In August 2010, the FERC issued three Orders accepting most facets of several MISO RSG compliance filings. The FERC ordered the MISO to issue refunds for RSG charges that were imposed by the MISO on the assumption that there were rate mismatches for the period beginning November 5, 2007 through the present. There is no financial statement impact to the Company from this Order, as the MISO had anticipated that the FERC would require these refunds and had preemptively included them in the resettlements paid in 2009. The FERC denied the MISO's proposal to exempt certain resources from RSG charges, effective prospectively. The FERC accepted portions and rejected portions of the MISO's proposed RSG rate Redesign Proposal, which will be effective when the software is ready for implementation subject to further compliance filings. The impact of the Redesign Proposal on the Company cannot be estimated at this time.

Pension and Postretirement Benefits

KU accounts for pension and postretirement benefits in accordance with the compensation – retirement benefits guidance of the FASB ASC. This guidance requires employers to recognize the over-funded or under-funded status of a defined benefit pension and postretirement plan as an asset or liability on the Balance Sheets and to recognize through other comprehensive income the changes in the funded status in the year in which the changes occur. Under the regulated operations guidance of the FASB ASC, KU can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky and Virginia is based on the compensation – retirement benefits guidance of the FASB ASC. Regulators have been clear and consistent with their historical treatment of such rate recovery; therefore, the Company has recorded a regulatory asset representing the change in funded status of its pension plan that is expected to be recovered and a regulatory liability representing the change in funded status of its postretirement benefit plan. The regulatory asset and liability will be adjusted annually as prior service cost and actuarial gains and losses are recognized in net periodic benefit cost.

Storm Restoration

In January 2009, a significant ice storm passed through KU's service area causing approximately 199,000 customer outages, followed closely by a severe wind storm in February 2009, causing approximately 44,000 customer outages. An application was filed with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the establishment of a regulatory asset of up to $62 million based on actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, a regulatory asset of $57 million was established for actual costs incurred and approval was received in KU's 2010 base rate case to recover this asset over a ten year period beginning August 1, 2010.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service area causing significant outages and system damage. In October 2008, an application was filed with the

Kentucky Commission requesting approval to establish regulatory assets and defer for future recovery approximately $3 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the establishment a regulatory asset of up to $3 million based on actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, a regulatory asset of $2 million was established for actual costs incurred and KU received approval in its 2010 base rate case to recover this asset over a ten year period, beginning August 1, 2010.

Unamortized Loss on Bonds

The costs of early extinguishment of debt, including call premiums, legal and other expenses, and any unamortized balance of debt expense are amortized using the straight-line method, which approximates the effective interest method, over the life of either the replacement debt (in the case of refinancing) or the original life of the extinguished debt.

CMRG and KCCS Contributions

In July 2008, KU and LG&E, along with Duke Energy Kentucky, Inc. and Kentucky Power Company, filed an application with the Kentucky Commission requesting approval to establish regulatory assets related to contributions to the CMRG for the development of technologies for reducing carbon dioxide emissions and the KCCS to study the feasibility of geologic storage of carbon dioxide. The filing companies proposed that these contributions be treated as regulatory assets to be deferred until recovery is provided in the next base rate case of each company, at which time the regulatory assets will be amortized over the life of each project: four years with respect to the KCCS and ten years with respect to the CMRG. KU and LG&E jointly agreed to provide $2 million over two years to the KCCS and up to $2 million over ten years to the CMRG. In October 2008, an Order approving the establishment of the requested regulatory assets was received. KU received approval from the Kentucky Commission in the Company's 2010 Kentucky base rate case to recover these regulatory assets over the requested period beginning August 1, 2010.

Rate Case Expenses

KU incurred $1 million in expenses related to the development and support of the 2008 Kentucky base rate case. The Kentucky Commission approved the establishment of a regulatory asset for these expenses and authorized amortization over three years beginning in March 2009.

KU incurred $2 million in expenses related to the development and support of the 2010 Kentucky base rate case. The Kentucky Commission approved the establishment of a regulatory asset for these expenses and authorized amortization over three years beginning in August 2010.

FERC Jurisdictional Pension Costs

Other regulatory assets include pension costs of $5 million incurred by the Company and allocated to its FERC jurisdictional ratepayers. The Company will seek recovery of this asset in the next FERC rate proceeding.

Deferred Storm Costs

Based on an Order from the Kentucky Commission in June 2004, KU reclassified from maintenance expense to a regulatory asset $4 million related to costs not reimbursed from the 2003 ice storm. These costs were amortized through June 2009. KU earned a return of these amortized costs, which were included in jurisdictional operating expenses.

DSM

DSM consists of energy efficiency programs which are intended to reduce peak demand and delay the investment in additional power plant construction, provide customers with tools and information to become better managers of their energy usage and prepare for potential future legislation governing energy efficiency. KU's rates contain a DSM provision which includes a rate mechanism that provides for concurrent recovery of DSM costs and provides an incentive for implementing DSM programs. The provision allows KU to recover revenues from lost sales associated with the DSM programs based on program plan engineering estimates and post-implementation evaluations.

In July 2007, KU and LG&E filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. KU and LG&E filed revised tariffs in April 2008, under authority of this Order, which were effective in May 2008.

Emission Allowances

In November 2010, purchase accounting adjustments were recorded for the fair market value of KU's SO_2, NOx ozone season and NOx annual emission allowances. Offsetting regulatory assets or liabilities for fair value purchase accounting adjustments eliminate any ratemaking impact of the fair value adjustments. KU is granted SO_2 emission allowances through 2040 and NOx ozone season and NOx annual emission allowances through 2011.

Accumulated Cost of Removal of Utility Plant

As of December 31, 2010 and 2009, KU segregated the cost of removal, previously embedded in accumulated depreciation, of $348 million and $335 million, respectively, in accordance with FERC Order No. 631. For reporting purposes on the Balance Sheets, KU presented this cost of removal as a "Regulatory liability" pursuant to the regulated operations guidance of the FASB ASC.

OVEC Power Purchase Contract

In November 2010, purchase accounting adjustments were recorded for the fair value of the power purchase agreement between KU and OVEC. Offsetting regulatory liability for fair value purchase accounting adjustment eliminate any ratemaking impact of the fair value adjustments.

Deferred Income Taxes – Net

These regulatory liabilities represent the future revenue impact from the reversal of deferred income taxes required for unamortized investment tax credits, the allowance for funds used during construction and deferred taxes provided at rates in excess of currently enacted rates.

Other Regulatory Matters

Kentucky Commission Report on Storms

In November 2009, the Kentucky Commission issued a report following review and analysis of the effects and utility response to the September 2008 wind storm and the January 2009 ice storm and possible utility industry preventative measures relating thereto. The report suggested a number of proposed or recommended preventative or responsive measures, including consideration of selective hardening of facilities, altered vegetation management programs, enhanced customer outage communications and similar measures. In March 2010, the Utilities filed a joint response reporting on their actions with respect to such recommendations. The response indicated implementation or completion of substantially all of the recommendations, including, among other matters, on-going reviews of system hardening and vegetation management procedures, certain test or pilot programs in such areas and fielding of enhanced operational and customer outage-related systems.

Wind Power Agreements

In August 2009, KU and LG&E filed a notice of intent with the Kentucky Commission indicating their intent to file an application for approval of wind power purchase contracts and cost recovery mechanisms. The contracts were executed in August 2009 and were contingent upon KU and LG&E receiving acceptable regulatory approvals. Pursuant to the proposed 20-year contracts, KU and LG&E would jointly purchase respective assigned portions of the output of two Illinois wind farms totaling an aggregate 109.5 Mw. In September 2009, the Utilities filed an application and supporting testimony with the Kentucky Commission. In October 2009, the Kentucky Commission issued an Order denying the Utilities' request to establish a surcharge for recovery of the costs of purchasing wind power. The Kentucky Commission stated that such recovery constitutes a general rate adjustment and is subject to the regulations of a base rate case. The Kentucky Commission Order provided for the request for approval of the wind power agreements to proceed independently from the request to recover the costs thereof via surcharges. In November 2009, KU and LG&E filed for rehearing of the Kentucky Commission's Order and requested that the matters of approval of the contract and recovery of the costs thereof remain the subject of the same proceeding. During December 2009, the Kentucky Commission issued data requests on this matter. In March 2010, the Utilities delivered notices of termination under provisions of the wind power contracts. The Utilities also filed a motion with the Kentucky Commission noting the termination of the contracts and seeking withdrawal of their application in the related regulatory proceeding. In April 2010, the Kentucky Commission issued an Order allowing the Utilities to withdraw their pending application.

Trimble County Asset Purchase and Depreciation

In July 2009, the Utilities notified the Kentucky Commission of the proposed sale from the Utilities of certain ownership interests in certain existing Trimble County generating station assets which were

anticipated to provide joint or common use in support of the jointly-owned TC2 generating unit under construction at the station. The undivided ownership interests sold provide KU an ownership interest in these common assets proportional to its interest in TC2 and the assets' role in supporting both TC1 and TC2. In December 2009, the Utilities completed the sale transaction at a price of $48 million, representing the current net book value of the assets multiplied by the proportional interest being sold.

In August 2009, the Utilities jointly filed an application with the Kentucky Commission to approve new depreciation rates for applicable jointly-owned TC2-related generating, pollution control and other plant equipment and assets. During December 2009, the Kentucky Commission extended the data discovery process through January 2010 and authorized the Utilities on an interim basis to begin using the depreciation rates for TC2 as proposed in the application. In March 2010, the Kentucky Commission issued a final Order approving the use of the proposed depreciation rates on a permanent basis.

TC2 CCN Application and Transmission Matters

An application for a CCN for construction of TC2 was approved by the Kentucky Commission in November 2005. CCNs for two transmission lines associated with TC2 were issued by the Kentucky Commission in September 2005 and May 2006. All regulatory approvals and rights of way for one transmission line have been obtained.

KU's and LG&E's CCN for a transmission line associated with the TC2 construction has been challenged by certain property owners in Hardin County, Kentucky. Certain proceedings relating to CCN challenging and federal historic preservation permit requirements have concluded with outcomes in the Utilities' favor.

Completion of the transmission lines are also subject to standard construction permit, environmental authorization and real property or easement acquisition procedures. Certain Hardin County landowners have raised challenges to the transmission line in some of these forums as well.

With respect to the remaining on-going dispute, KU obtained various successful rulings during 2008 at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals and received a temporary stay preventing KU from accessing their properties. In May 2010, the Kentucky Court of Appeals issued an Order affirming the Hardin Circuit Court's finding that KU had the right to condemn easements on the properties. In May 2010, the landowners filed a petition for reconsideration with the Court of Appeals. In July 2010, the Court of Appeals denied that petition. In August, 2010, the landowners filed for discretionary review of that denial by the Kentucky Supreme Court.

Settlement discussions with the Hardin County property owners involved in the appeals of the condemnation proceedings have been unsuccessful to date. During the fourth quarter of 2008, KU and LG&E entered into settlements with certain Meade County landowners and obtained dismissals of prior litigation they brought challenging the same transmission line.

As a result of the aforementioned unresolved litigation delays encountered in obtaining access to certain properties in Hardin County, KU obtained easements to allow construction of temporary transmission facilities, bypassing those properties while the litigated issues are resolved. In September 2009, the Kentucky Commission issued an Order stating that a CCN was necessary for two segments of the

proposed temporary facilities. In December 2009, the Kentucky Commission granted the CCNs for the relevant segments and the property owners have filed various motions to intervene, stay and appeal certain elements of the Kentucky Commission's recent orders. In January 2010, in respect of two of such proceedings, the Franklin County circuit court issued Orders denying the property owners' request for a stay of construction and upholding the prior Kentucky Commission denial of their intervenor status.

Consistent with the regulatory authorizations and the favorable outcome of the legal proceedings, the Utilities completed construction activities on the permanent transmission line easements. During 2010, the Utilities placed the transmission line into operation. While the Utilities are not currently able to predict the ultimate outcome and possible financial effects of the remaining legal proceedings, the Utilities do not believe the matter involves relevant or continuing risks to operations.

Utility Competition in Virginia

The Commonwealth of Virginia passed the Virginia Electric Utility Restructuring Act in 1999. This act gave customers the ability to choose their electric supplier and capped electric rates through December 2010. KU subsequently received a legislative exemption from the customer choice requirements of this law. In April 2007, however, the Virginia General Assembly amended the Virginia Electric Utility Restructuring Act, thereby terminating this competitive market and commencing re-regulation of utility rates. The new act ended the cap on rates at the end of 2008. Pursuant to this legislation, the Virginia Commission adopted regulations revising the rules governing utility rate increase applications. As of January 2009, a hybrid model of regulation is being applied in Virginia. Under this model, utility rates are reviewed every two years. KU's exemption from the requirements of the Virginia Electric Utility Restructuring Act in 1999, however, discharges the Company from the requirements of the new hybrid model of regulation. In lieu of submitting an annual information filing, the Company has the option of requesting a change in base rates to recover prudently incurred costs by filing a traditional base rate case. KU is also subject to other utility regulations in Virginia, including, but not limited to, the recovery of prudently incurred fuel costs through an annual fuel factor charge and the submission of integrated resource plans.

Market-Based Rate Authority

In July 2006, the FERC issued an Order in KU's market-based rate proceeding accepting the Company's further proposal to address certain market power issues the FERC claimed would arise upon an exit from the MISO. In particular, the Company received permission to sell power at market-based rates at the interface of balancing areas in which it may be deemed to have market power, subject to a restriction that such power will not be collusively re-sold back into such balancing areas. However, restrictions exist on sales by KU of power at market-based rates in the KU and LG&E and Big Rivers Electric Company balancing areas. In June 2007, the FERC issued Order No. 697 implementing certain reforms to market-based rate regulations, including restrictions similar to those previously in place for the Company's power sales at balancing area interfaces. In December 2008, the FERC issued Order No. 697-B potentially placing additional restrictions on certain power sales involving areas where market power is deemed to exist. As a condition of receiving and retaining market-based rate authority, KU must comply with applicable affiliate restrictions set forth in the FERC regulation. During September 2008, the Company submitted a regular triennial update filing under market-based rate regulations.

In June 2009, the FERC issued Order No. 697-C which generally clarified certain interpretations relating to power sales and purchases at balancing area interfaces or into balancing areas involving market power. In July 2009, the FERC issued an Order approving the Company's September 2008 application for market-based rate authority. During July 2009, affiliates of KU completed a transaction terminating certain prior generation and power marketing activities in the Big Rivers Electric Company balancing area, which termination should ultimately allow a filing to request a determination that the Company no longer is deemed to have market power in such balancing area.

KU conducts certain of its wholesale power sales activities in accordance with existing market-based rate authority principles and interpretations. Future FERC proceedings relating to Orders 697 or market-based rate authority could alter the amount of sales made at market-based versus cost-based rates. The Company's sales under market-based rate authority totaled less than $1 million for the year ended December 31, 2010.

Mandatory Reliability Standards

As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007 and authority was delegated to various Regional Reliability Organizations ("RROs") by the NERC, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. The Utilities are members of the SERC, which acts as KU's and LG&E's RRO. During December 2009 and April, July and August 2010, the Utilities submitted ten self-reports relating to various standards, which self-reports remain in the early stages of RRO review, and therefore, the Utilities are unable to estimate the outcome of these matters. Mandatory reliability standard settlements commonly also include non-penalty elements, including compliance steps and mitigation plans. Settlements with SERC proceed to NERC and FERC review before becoming final. While the Utilities believe they are in compliance with the mandatory reliability standards, events of potential non-compliance may be identified from time-to-time. The Utilities cannot predict such potential violations or the outcome of self-reports described above.

Integrated Resource Planning

Integrated resource planning ("IRP") regulations in Kentucky require major utilities to make triennial IRP filings with the Kentucky Commission. In April 2008, KU and LG&E filed their 2008 joint IRP with the Kentucky Commission. The IRP provides historical and projected demand, resource and financial data and other operating performance and system information. The Kentucky Commission issued a staff report and Order closing this proceeding in December 2009. Pursuant to the Virginia Commission's December 2008 Order, KU filed its IRP in July 2009. The filing consisted of the 2008 Joint IRP filed by KU and LG&E with the Kentucky Commission along with additional data. The Virginia Commission has not established a procedural schedule for this proceeding. KU expects to file their next IRP in April 2011.

PUHCA 2005

PPL, KU's ultimate parent, is a holding company under PUHCA 2005. PPL, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries, are subject to extensive regulation by the FERC

with respect to numerous matters, including electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. KU believes that it has adequate authority, including financing authority, under existing FERC Orders and regulations to conduct its business and will seek additional authorization when necessary.

EPAct 2005

The EPAct 2005 was enacted in August 2005. Among other matters, this comprehensive legislation contains provisions mandating improved electric reliability standards and performance; granting enhanced civil penalty authority to the FERC; providing economic and other incentives relating to transmission, pollution control and renewable generation assets; increasing funding for clean coal generation incentives; repealing the Public Utility Holding Company Act of 1935; enacting PUHCA 2005; and expanding FERC jurisdiction over public utility holding companies and related matters via the Federal Power Act and PUHCA 2005.

In February 2006, the Kentucky Commission initiated an administrative proceeding to consider the requirements of the EPAct 2005, Subtitle E Section 1252, Smart Metering, which concerns time-based metering and demand response, and Section 1254, Interconnections. EPAct 2005 requires each state regulatory authority to conduct a formal investigation and issue a decision on whether or not it is appropriate to implement certain Section 1252 standards within eighteen months after the enactment of EPAct 2005 and to commence consideration of Section 1254 standards within one year after the enactment of EPAct 2005. Following a public hearing with all Kentucky jurisdictional electric utilities, in December 2006, the Kentucky Commission issued an Order in this proceeding indicating that the EPAct 2005 Section 1252 and Section 1254 standards should not be adopted. However, all five Kentucky Commission jurisdictional utilities were required to file real-time pricing pilot programs for their large commercial and industrial customers. KU developed a real-time pricing pilot program for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by KU for implementation within approximately eight months. The tariff was filed in October 2008, with an effective date of December 1, 2008. KU files annual reports on the program within 90 days of each plan year end for the three-year pilot period.

Green Energy Riders

In February 2007, KU and LG&E filed a Joint Application and Testimony for Proposed Green Energy Riders. In May 2007, a Kentucky Commission Order was issued authorizing KU to establish Small and Large Green Energy Riders, allowing customers to contribute funds to be used for the purchase of renewable energy credits. During November 2009, KU and LG&E filed an application to both continue and modify the existing Green Energy Programs. In February 2010, the Kentucky Commission approved the Utilities' application, as filed.

Home Energy Assistance Program

In July 2007, KU filed an application with the Kentucky Commission for the establishment of a Home Energy Assistance program. During September 2007, the Kentucky Commission approved the five-year

program as filed, effective in October 2007. The programs were scheduled to terminate in September 2012 and is funded through a $0.10 per month meter charge. Effective February 6, 2009, as a result of the settlement agreement in the 2008 base rate case, the program is funded through a $0.15 per month meter charge. As a condition in the settlement in the change of control proceeding before the Kentucky Commission in the PPL acquisition, the program was extended to September 2015.

Collection Cycle Revision

As part of its base rate case filed on July 29, 2008, LG&E proposed to change the due date for customer bill payments from 15 days to 10 days to align its collection cycle with KU. In addition, in its rate case filed on July 29, 2008, KU proposed to include a late payment charge if payment is not received within 15 days from the bill issuance date to align with LG&E. The settlement agreements approved in the rate cases in February 2009 changed the due date for customer bill payments to 12 days after bill issuance for both KU and LG&E and permitted KU's implementation of a late payment charge if payment is not received within 15 days from the bill issuance date.

Depreciation Study

In December 2007, KU filed a depreciation study with the Kentucky Commission as required by a previous Order. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding. The approved settlement agreements in the rate cases established new depreciation rates effective February 2009. KU also filed the depreciation study with the Virginia Commission which approved the implementation of the new depreciation rates effective February 2009. Approval by the Virginia Commission does not preclude the rates from being raised as an issue by any party in KU's future base rate cases in Virginia.

Brownfield Development Rider Tariff

In March 2008, KU received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a Brownfield site, as certified by the appropriate Kentucky state agency. The rider permits special contracts with such customers which provide for a series of declining partial rate discounts over an initial five-year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant Brownfield sites.

Interconnection and Net Metering Guidelines

In May 2008, the Kentucky Commission on its own motion initiated a proceeding to establish interconnection and net metering guidelines in accordance with amendments to existing statutory requirements for net metering of electricity. The jurisdictional electric utilities and intervenors in this case presented proposed interconnection guidelines to the Kentucky Commission in October 2008. In a January 2009 Order, the Kentucky Commission issued the Interconnection and Net Metering Guidelines – Kentucky that were developed by all parties to the proceeding. KU does not expect any financial or other impact as a result of this Order. In April 2009, KU filed revised net metering tariffs and application forms pursuant to the Kentucky Commission's Order. The Kentucky Commission issued an Order in April 2009, which suspended for five months all net metering tariffs filed by the jurisdictional

electric utilities. This suspension was intended to allow sufficient time for review of the filed tariffs by the Kentucky Commission Staff and intervening parties. In June 2009, the Kentucky Commission Staff held an informal conference with the parties to discuss issues related to the net metering tariffs filed by KU. Following this conference, the intervenors and KU resolved all issues and KU filed revised net metering tariffs with the Kentucky Commission. In August 2009, the Kentucky Commission issued an Order approving the revised tariffs.

EISA 2007 Standards

In November 2008, the Kentucky Commission initiated an administrative proceeding to consider new standards as a result of the Energy Independence and Security Act of 2007 ("EISA 2007"), part of which amends the Public Utility Regulatory Policies Act of 1978 ("PURPA"). There are four new PURPA standards and one non-PURPA standard applicable to electric utilities. The proceeding also considers two new PURPA standards applicable to natural gas utilities. EISA 2007 requires state regulatory commissions and non-regulated utilities to begin consideration of the rate design and smart grid investments no later than December 19, 2008 and to complete the consideration by December 19, 2009. The Kentucky Commission established a procedural schedule that allowed for data discovery and testimony through July 2009. In October 2009, the Kentucky Commission held an informal conference for the purpose of discussing issues related to the standard regarding the consideration of Smart Grid investments. A public hearing has not been scheduled in this matter.

Note 4 - Asset Retirement Obligations

A summary of KU's net ARO assets, ARO liabilities and regulatory assets established under the asset retirement and environmental obligations guidance of the FASB ASC follows:

	ARO Net Assets	ARO Liabilities	Regulatory Assets
As of December 31, 2008, Predecessor	$ 5	$ (32)	$ 28
ARO accretion and depreciation	(1)	(2)	2
As of December 31, 2009, Predecessor	4	(34)	30
ARO accretion and depreciation	-	(2)	2
Reclassification for retired assets	(1)	-	1
ARO revaluation - change in estimates	22	(24)	2
As of October 31, 2010, Predecessor	25	(60)	35
ARO accretion and depreciation	(1)	-	1
Purchase accounting - fair value adjustment	28	6	(34)
As of December 31, 2010, Successor	$ 52	$ (54)	$ 2

In September 2010, the Company performed a revaluation of its AROs as a result of recently proposed environmental legislation and improved ability to forecast asset retirement costs due to recent construction and retirement activity.

In November 2010, the Company recorded a purchase accounting adjustment to fair value AROs due to the PPL acquisition.

Pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC, an offsetting regulatory credit was recorded in "Depreciation and amortization" in the Statements of Income for the Successor of $1 million in 2010 and $2 million for the Predecessor for the ARO accretion and depreciation expense. The offsetting regulatory credit recorded was $2 million in 2009 and 2008 for the ARO accretion and depreciation expense. The ARO liabilities are offset by cash settlements that have not yet been applied. Therefore, ARO net assets, ARO liabilities and regulatory assets balances do not net to zero due to the cash settlements.

KU's AROs are primarily related to the final retirement of assets associated with generating units. KU transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under the asset retirement and environmental obligations guidance of the FASB ASC, no material asset retirement obligations are recorded for transmission and distribution assets.

Note 5 – Derivative Financial Instruments

KU is subject to interest rate and commodity price risk related to on-going business operations. The Company's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. Although the Company's policies allow for the use of interest rate swaps, as of December 31, 2010 and 2009, KU had no interest rate swaps outstanding. At December 31, 2010, KU's potential annual exposure to increased interest expense, based on a 10% increase in interest rates, was less than $1 million.

The Company does not net collateral against derivative instruments.

Energy Trading and Risk Management Activities

KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to manage price risk and are accounted for as non-hedging derivatives on a mark-to-market basis in accordance with the derivatives and hedging guidance of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from Intercontinental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity data is unavailable, other inputs include prices quoted by brokers or observable inputs other than quoted prices, such as one-sided bids or offers as of the balance sheet date. Quotes are verified quarterly using an independent pricing source of actual transactions. Quotes for combined off-peak and weekend timeframes are allocated between the two timeframes based on their historical proportional ratios to the integrated cost. No other adjustments are made to the forward prices. No changes to valuation techniques for energy trading and risk management activities occurred during 2010 or 2009. Changes in market pricing, interest rate and volatility assumptions were made during both years.

KU's financial assets and liabilities as of December 31, 2010 and December 31, 2009, arising from energy trading and risk management contracts not designated as hedging instruments accounted for at fair value total less than $1 million and are recorded in prepayments and other current assets and other current liabilities, respectively.

The Company maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, KU seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. The Company uses ratings of S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, KU assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At December 31, 2010, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. The Company has reserved against counterparty credit risk based on KU's own creditworthiness (for net liabilities) and its counterparty's creditworthiness (for net assets). The Company applies historical default rates within varying credit ratings over time provided by S&P or Moody's. At December 31, 2010 and December 31, 2009, counterparty credit reserves related to energy trading and risk management contracts were less than $1 million.

The net volume of electricity based financial derivatives outstanding at December 31, 2010 and December 31, 2009, was 129,199 Mwh and 315,600 Mwh, respectively. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2010 and December 31, 2009. Cash collateral related to the energy trading and risk management contracts is recorded in "Prepayments and other current assets" on the Balance Sheets.

KU manages the price risk of its estimated future excess economic generation capacity using market-traded forward contracts. Hedge accounting treatment has not been elected for these transactions; therefore, realized and unrealized gains and losses are included in the Statements of Income.

The following table presents the effect of market-traded forward contract derivatives not designated as hedging instruments on income:

Loss Recognized in Income	Location	Successor: November 1, 2010 through December 31, 2010	Predecessor: January 1, 2010 through October 31, 2010	Predecessor: Year Ended December 31, 2009	Predecessor: Year Ended December 31, 2008
Unrealized gain (loss)	Electric revenues	$ -	$ -	$ (1)	$ 1

Net realized gains and losses were zero for the period ended December 31, 2010 and less than $1 million for the periods ended October 31, 2010, December 31, 2009 and December 31, 2008.

Credit Risk Related Contingent Features

Certain of KU's derivative contracts contain credit contingent provisions which would permit the counterparties with which KU is in a net liability position to require the transfer of additional collateral upon a decrease in KU's credit rating. Some of these provisions would require KU to transfer additional collateral or permit the counterparty to terminate the contract if KU's credit rating were to fall below investment grade. Some of these provisions also allow the counterparty to require additional collateral upon each decrease in the credit rating at levels that remain above investment grade. In either case, if KU's credit rating were to fall below investment grade (i.e., below BBB- for S&P or Baa3 for Moody's), and assuming no assignment to an investment grade affiliate were allowed, most of these credit contingent provisions require either immediate payment of the net liability as a termination payment or immediate and ongoing full collateralization by KU on derivative instruments in net liability positions.

Additionally, certain of KU's derivative contracts contain credit contingent provisions that require KU to provide "adequate assurance" of performance if the other party has reasonable grounds for insecurity regarding KU's performance of its obligation under the contract. A counterparty demanding adequate assurance could require a transfer of additional collateral or other security, including letters of credit, cash and guarantees from a creditworthy entity. A demand for additional assurance would typically involve negotiations among the parties.

To determine net liability positions, KU uses the fair value of each agreement. At December 31, 2010, there were no energy trading and risk management derivative contracts with credit risk related contingent features that are in a liability position and collateral of less than $1 million was posted in the normal course of business. At December 31, 2010, a downgrade of the Company's credit rating below investment grade would have no effect on the energy trading and risk management derivative contracts or collateral required.

Note 6 - Fair Value Measurements

KU adopted the fair value guidance in the FASB ASC in two phases. Effective January 1, 2008, the Company adopted it for all financial instruments and non-financial instruments accounted for at fair value on a recurring basis, and effective January 1, 2009, the Company adopted it for all non-financial instruments accounted for at fair value on a non-recurring basis. The FASB ASC guidance clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. As a basis for considering such assumptions, the FASB ASC guidance establishes a three-tier value hierarchy, which prioritizes the inputs used in the valuation methodologies in measuring fair value.

The carrying values and estimated fair values of KU's non-trading financial instruments follow:

	Successor		Predecessor	
	December 31, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term bonds	$ 1,841	$ 1,728	$ 351	$ 351
Long-term debt to affiliated company	-	-	1,331	1,401

The long-term fixed rate pollution control bond valuations reflect prices quoted by investment banks, which are active in the market for these instruments. First mortgage bond valuations reflect prices quoted from a third party service. The fair value of the long-term debt due to affiliated company is determined using an internal valuation model that discounts the future cash flows of each loan at current market rates as determined based on quotes from investment banks that are actively involved in capital markets for utilities and factor in KU's credit ratings and default risk. The fair values of cash and cash equivalents, accounts receivable, cash surrender value of key man life insurance, accounts payable and notes payable are substantially the same as their carrying values.

KU has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures guidance of the FASB ASC, as discussed in Note 1, Summary of Significant Accounting Policies.

The Company classifies its derivative cash collateral balances within level 1 based on the funds being held in a demand deposit account. The Company classifies its derivative energy trading and risk management contracts within level 2 because it values them using prices actively quoted for proposed or executed transactions, quoted by brokers or observable inputs other than quoted prices.

KU's financial assets and liabilities as of December 31, 2010 and 2009, arising from energy trading and risk management contracts accounted for at fair value on a recurring basis total less than $1 million. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2010 and December 31, 2009 each year.

There were no level 3 measurements for the periods ending December 31, 2010 and December 31, 2009.

Note 7 - Goodwill and Intangible Assets

In connection with PPL's acquisition of LKE, KU recorded goodwill on November 1, 2010. In addition, as of November 1, 2010, certain intangible assets were adjusted to their fair value and new intangible assets were recorded. See Note 2, Acquisition by PPL, for further information.

<u>Goodwill</u>

The Company performs its required annual goodwill impairment test in the fourth quarter. Impairment tests are performed between the annual tests when the Company determines that a triggering event has occurred that would, more likely than not, reduce the fair value of a reporting unit below its carrying value. The goodwill impairment test is comprised of a two-step process. In step 1, the Company identifies a potential impairment by comparing the estimated fair value of the regulated utilities (the

goodwill reporting unit) to their carrying value, including goodwill, on the measurement date. If the estimated fair value exceeds its carrying amount, goodwill is not considered impaired. If the fair value is less than the carrying value, then step 2 is performed to measure the amount of impairment loss, if any. The step 2 calculation compares the implied fair value of the goodwill to the carrying value of the goodwill. The implied fair value of goodwill is equal to the excess of the Company estimated fair value over the fair values of its identified assets and liabilities. If the carrying value of goodwill exceeds the implied fair value of goodwill, an impairment loss is recognized in an amount equal to that excess (but not in excess of the carrying value).

In connection with PPL's acquisition of LKE on November 1, 2010, goodwill of $607 million was recorded on November 1, 2010. The allocation of the goodwill to KU was based on the net asset value of the Company. The goodwill represents value paid for the rate regulated business located in a defined service area with a constructive regulatory environment, which provides for future investment, earnings and cash flow growth, as well as the talented and experienced workforce. KU's franchise values are being attributed to the going concern value of the business and thus were recorded as goodwill rather than a separately identifiable intangible asset. None of the goodwill recognized is expected to be deductible for income tax purposes or included in customer rates. See Note 2, Acquisition by PPL, for further information.

For the 2010 annual impairment test, the primary valuation technique used was an income methodology based on management's estimates of forecasted cash flows for the Company, with those cash flows discounted to present value using rates commensurate with the risks of those cash flows. Management also took into consideration the acquisition price paid by PPL. The discounted cash flows for the Company was based on discrete financial forecasts developed by management for planning purposes and consistent with those given to PPL. Cash flows beyond the discrete forecasts were estimated using a terminal-value calculation, which incorporated historical and forecasted financial trends for the Company. No impairment resulted from the fourth quarter test, as the determined fair value of the Company was greater than its carrying value.

Other Intangible Assets

The gross carrying amount and the accumulated amortization of other intangible assets were as follows:

	Successor	
	December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:		
Coal contracts (a)	$ 145	$ 3
Land rights (b)	8	-
Emission allowances (c)	9	-
OVEC power purchase agreement (d)	39	1
Total other intangible assets	$ 201	$ 4

(a) The gross carrying amount represents the fair value of coal contracts recognized as a result of the 2010 acquisition by PPL. The weighted average amortization period of these contracts is 3 years. See Note 2, Acquisition by PPL, for further information.

(b) The gross carrying amount represents the fair value of land rights recognized as a result of adopting PPL's accounting policies in the Successor period. The weighted average amortization period of these rights is 17 years. See Note 1, Summary of Significant Accounting Policies, for further information.
(c) The gross carrying amount represents the fair value of emission allowances recognized as a result of the 2010 acquisition by PPL, as well as the reclassification of amounts from inventory to intangible assets as a result of adopting PPL's accounting policies in the Successor period. The weighted average amortization period of these emission allowances is 3 years. See Note 2, Acquisition by PPL, for further information.
(d) The gross carrying amount represents the fair value of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. The weighted average amortization period of the power purchase agreement is 8 years. See Note 2, Acquisition by PPL, for further information.

Current intangible assets and long-term intangible assets are included in "Other intangible assets" in their respective areas on the Balance Sheets in 2010. Intangible assets resulting from purchase accounting adjustments are not recoverable in rates.

Amortization expense, excluding consumption of emission allowances, was $4 million for the Successor in 2010. The estimated aggregate amortization expense for each of the next five years is as follows:

	Estimated Expense in Period Ended				
	2011	2012	2013	2014	2015
Aggregate amortization expense	$ 43	$ 25	$ 27	$ 24	$ 26

Note 8 - Concentrations of Credit and Other Risk

Credit risk represents the accounting loss that would be recognized at the reporting date if counterparties failed to perform as contracted. Concentrations of credit risk (whether on- or off-balance sheet) relate to groups of customers or counterparties that have similar economic or industry characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

All of KU's customer receivables arise from deliveries of electricity. During 2010, the Company's ten largest customers accounted for less than 19% of volumes.

Effective August 4, 2009, KU and its employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement. The agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. KU and its employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement in August 2008. This agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. The employees represented by these two bargaining units comprise approximately 15% of the Company's workforce at December 31, 2010.

Note 9 - Pension and Other Postretirement Benefit Plans

KU employees benefit from both funded and unfunded retirement benefit plans. Its defined benefit pension plan covers employees hired by December 31, 2005. Employees hired after this date participate in the Retirement Income Account ("RIA"), a defined contribution plan. The postretirement plan includes health care benefits that are contributory, with participants' contributions adjusted annually. The Company uses December 31 as the measurement date for its plans.

Obligations and Funded Status

The following tables provide a reconciliation of the changes in the defined benefit plans' obligations, the fair value of assets and the funded status of the plans for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 355	$ 316	$ 306	$ 84	$ 80	$ 75
Service cost	1	5	6	-	1	2
Interest cost	3	16	18	1	4	4
Benefits paid, net of retiree contributions	(3)	(14)	(18)	(1)	(4)	(5)
Actuarial (gain) loss and other	(2)	32	4	(1)	3	4
Benefit obligation at end of period	$ 354	$ 355	$ 316	$ 83	$ 84	$ 80

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 237	$ 219	$ 183	$ 20	$ 17	$ 12
Actual return on plan assets	7	20	41	-	1	3
Employer contributions	-	13	13	2	6	7
Benefits paid, net of retiree contributions	(3)	(14)	(18)	(1)	(4)	(5)
Administrative expenses and other	-	(1)	-	-	-	-
Fair value of plan assets at end of period	$ 241	$ 237	$ 219	$ 21	$ 20	$ 17
Funded status at end of period	$ (113)	$ (118)	$ (97)	$ (62)	$ (64)	$ (63)

Amounts Recognized in the Balance Sheets

The following tables provide the amounts recognized in the Balance Sheets and information for plans with benefit obligations in excess of plan assets plans for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Regulatory assets	$ 117	$ 125	$ 105	$ -	$ -	$ -
Regulatory liabilities	-	-	-	(10)	(9)	(9)
Accrued benefit liability (non-current)	(113)	(118)	(97)	(62)	(64)	(63)

Amounts recognized in regulatory assets and liabilities for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Transition obligation	$ -	$ -	$ -	$ 2	$ 2	$ 3
Prior service cost	3	4	5	1	1	2
Accumulated loss (gain)	114	121	100	(13)	(12)	(14)
Total regulatory assets and liabilities	$ 117	$ 125	$ 105	$ (10)	$ (9)	$ (9)

Additional information for plans with accumulated benefit obligations in excess of plan assets for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Benefit obligation	$ 354	$ 355	$ 316	$ 83	$ 84	$ 80
Accumulated benefit obligation	299	299	268	-	-	-
Fair value of plan assets	241	237	219	21	20	17

The amounts recognized in regulatory assets and liabilities for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Net (gain) loss arising during the period	$ (6)	$ 26	$ (22)	$ (1)	$ 2	$ 2
Amortization of prior service cost	-	(1)	(1)	-	-	-
Amortization of transitional obligation	-	-	-	-	(2)	(1)
Amortization of loss	(2)	(5)	(9)	-	-	-
Total amounts recognized in regulatory assets and liabilities	$ (8)	$ 20	$ (32)	$ (1)	$ -	$ 1

For discussion of the pension and postretirement regulatory assets, see Note 3, Rates and Regulatory Matters.

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost for pension and other postretirement benefit plans. The tables include the costs associated with both KU employees and Servco employees who provide services to KU. The Servco costs are allocated to KU based on employees' labor charges and are approximately 51%, 49% and 46% of Servco's costs for 2010, 2009 and 2008, respectively.

	Pension Benefits					
	Successor			Predecessor		
	November 1, 2010 through December 31, 2010			January 1, 2010 through October 31, 2010		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 1	$ 1	$ 2	$ 5	$ 5	$ 10
Interest cost	3	2	5	16	6	22
Expected return on plan assets	(3)	(1)	(4)	(14)	(5)	(19)
Amortization of prior service cost	-	-	-	1	1	2
Amortization of actuarial gain	2	-	2	5	2	7
Net periodic benefit cost	$ 3	$ 2	$ 5	$ 13	$ 9	$ 22

	Pension Benefits					
	Predecessor - Year Ended December 31, 2009			Predecessor - Year Ended December 31, 2008		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 6	$ 5	$ 11	$ 6	$ 4	$ 10
Interest cost	18	7	25	18	6	24
Expected return on plan assets	(15)	(4)	(19)	(21)	(5)	(26)
Amortization of prior service cost	1	1	2	1	1	2
Amortization of actuarial gain	9	2	11	-	-	-
Net periodic benefit cost	$ 19	$ 11	$ 30	$ 4	$ 6	$ 10

	Other Postretirement Benefits					
	Successor			Predecessor		
	November 1, 2010 through December 31, 2010			January 1, 2010 through October 31, 2010		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ -	$ -	$ -	$ 1	$ 1	$ 2
Interest cost	1	-	1	4	-	4
Expected return on plan assets	-	-	-	(1)	-	(1)
Amortization of transition obligation	-	-	-	1	-	1
Net periodic benefit cost	$ 1	$ -	$ 1	$ 5	$ 1	$ 6

	Other Postretirement Benefits					
	Predecessor - Year Ended December 31, 2009			Predecessor Year Ended December 31, 2008		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	5	-	5	5	-	5
Expected return on plan assets	(1)	-	(1)	(1)	-	(1)
Amortization of transition obligation	1	-	1	1	-	1
Net periodic benefit cost	$ 6	$ 1	$ 7	$ 6	$ 1	$ 7

The estimated amounts that will be amortized from regulatory assets and liabilities into net periodic benefit cost in 2011 are shown in the following table:

	Pension Benefits	Other Postretirement Benefits
Regulatory assets and liabilities:		
Net actuarial loss	$ 8	$ -
Prior service cost	1	1
Transition obligation	-	1
Total regulatory assets and liabilities amortized during 2011	$ 9	$ 2

The weighted average assumptions used in the measurement of KU's pension and postretirement benefit obligations for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor are shown in the following table:

	Successor	Predecessor	
	December 31, 2010	October 31, 2010	December 31, 2009
Discount rate – pension benefits	5.52%	5.46%	6.13%
Discount rate – postretirement benefits	5.12%	4.96%	5.82%
Rate of compensation increase	5.25%	5.25%	5.25%

For the first ten months of 2010, the discount rates used to determine the pension and postretirement benefit obligations and the period expense were determined using the Mercer Pension Discount Yield Curve. This model takes the plans' cash flows and matches them to a yield curve that provides the equivalent yields on zero-coupon corporate bonds for each maturity. The discount rate is the single rate

that produces the same present value of cash flows. The selection of the various discount rates represents the equivalent single rate under a broad-market AA yield curve constructed by Mercer.

For the last two months of 2010, the Towers Watson Yield Curve was used to determine the discount rate. This model also starts with an analysis of the expected benefit payment stream for its plans. This information is first matched against a spot-rate yield curve. A portfolio of Aa-graded non-callable (or callable with make-whole provisions) bonds, with a total amount outstanding in excess of $667 billion, serves as the base from which those with the lowest and highest yields are eliminated to develop the ultimate yield curve. The results of this analysis are considered together with other economic data and movements in various bond indices to determine the discount rate assumption.

The weighted average assumptions used in the measurement of KU's pension and postretirement net periodic benefit costs for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor are shown in the following table:

	Successor	Predecessor		
	2010	2010	2009	2008
Discount rate - pension	5.45%	5.46%	6.25%	6.66%
Discount rate - postretirement	4.94%	5.82%	6.36%	6.56%
Expected long-term return on plan assets	7.25%	7.75%	8.25%	8.25%
Rate of compensation increase	5.25%	5.25%	5.25%	5.25%

To develop the expected long-term rate of return on assets assumption, KU considered the current level of expected returns on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the current asset allocation to develop the expected long-term rate of return on assets assumption for the portfolio. The Company has determined that the 2011 expected long-term rate of return on assets assumption should be 7.25%.

The following describes the effects on pension benefits by changing the major actuarial assumptions discussed above:

- A 1% change in the assumed discount rate would have a $39 million positive or negative impact to the 2010 accumulated benefit obligation and an approximate $51 million positive or negative impact to the 2010 projected benefit obligation.
- A 25 basis point change in the expected rate of return on assets would have resulted in less than a $1 million positive or negative impact to 2010 pension expense.
- A 25 basis point increase in the rate of compensation increase would have a $3 million negative impact to the 2010 projected benefit obligation.

Assumed Health Care Cost Trend Rates

For measurement purposes, an 8% annual increase in the per capita cost of covered health care benefits was assumed for the first ten months of 2010. The rate was assumed to decrease gradually to 4.5% by 2029 and remain at that level thereafter. For the last two months of 2010, an 8% annual increase in the

per capita cost of covered health care benefits was assumed and the rate was assumed to decrease gradually to 5.5% by 2019. For 2011, a 9% annual increase in the per capita cost of covered health care benefits is assumed and the rate is assumed to decrease gradually to 5.5% by 2019. This change in the length of the health care trend was made to conform to PPL's accounting policies.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in assumed health care cost trend rates would have resulted in an increase or decrease of less than $1 million to the 2010 total of service and interest costs components and an increase or decrease of $4 million in year end 2010 postretirement benefit obligations.

Expected Future Benefit Payments and Medicare Subsidy Receipts

The following list provides the amount of expected future benefit payments, which reflect expected future service costs and the estimated gross amount of Medicare subsidy receipts:

	Pension Benefits	Other Postretirement Benefits	Medicare Subsidy Receipts
2011	$ 18	$ 6	$ 1
2012	18	6	-
2013	18	6	1
2014	18	7	-
2015	18	7	1
2016-2020	106	36	3

Plan Assets

The following table shows the pension plan's weighted average asset allocation by asset category at December 31:

	Target Range	Successor 2010	Predecessor 2009
Equity securities	45% - 75%	56%	59%
Debt securities	30% - 50%	24%	40%
Other	0% - 10%	20%	1%
Totals		100%	100%

The investment policy of the pension plans was developed in conjunction with financial and actuarial consultants, investment advisors and legal counsel. The goal of the investment policy is to preserve the capital of the pension plans' assets and maximize investment earnings in excess of inflation with acceptable levels of volatility. The return objective is to exceed the benchmark return for the policy index comprised of the following: Russell 3000 Index, MSCI-EAFE Index, Barclays Capital Aggregate and Barclays Capital U.S. Long Government/Credit Bond Index in proportions equal to the targeted asset allocation.

Evaluation of performance focuses on a long-term investment time horizon over rolling three and five-year periods. The assets of the pension plans are broadly diversified within different asset classes (equities, fixed income securities and cash equivalents).

To minimize the risk of large losses in a single asset class, no more than 5% of the portfolio will be invested in the securities of any one issuer with the exclusion of the U.S. government and its agencies. The equity portion of the fund is diversified among the market's various subsections to diversify risk, maximize returns and avoid undue exposure to any single economic sector, industry group or individual security. The equity subsectors include, but are not limited to, growth, value, small capitalization and international.

In addition, the overall fixed income portfolio may have an average weighted duration, or interest rate sensitivity which is within +/- 20% of the duration of the overall fixed income benchmark. Foreign bonds in the aggregate shall not exceed 10% of the total fund. The portfolio may include a limited investment of up to 20% in below investment grade securities provided that the overall average portfolio quality remains "AA" or better. The below investment grade securities include, but are not limited to, medium-term notes, corporate debt, non-dollar and emerging market debt and asset backed securities. The cash investments should be in securities that are either short maturities (not to exceed 180 days) or readily marketable with modest risk.

Derivative securities are permitted only to improve the portfolio's risk/return profile, to modify the portfolio's duration or to reduce transaction costs and must be used in conjunction with underlying physical assets in the portfolio. Derivative securities that involve speculation, leverage, interest rate anticipation, or any undue risk whatsoever are not deemed appropriate investments.

The investment objective for the postretirement benefit plan is to provide current income consistent with stability of principal and liquidity while maintaining a stable net asset value of $1.00 per share. The postretirement funds are invested in a prime cash money market fund that invests primarily in a portfolio of short-term, high-quality fixed income securities issued by banks, corporations and the U.S. government.

KU has classified plan assets that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures guidance of the FASB ASC. See Note 6, Fair Value Measurements, for further information.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs.

A description of the valuation methodologies used to measure plan assets at fair value is provided below:

> *Money market funds*: These investments are public investment vehicles valued using $1 for the net asset value. The money market funds are classified within level 2 of the valuation hierarchy.
>
> *Common/collective trusts:* Valued based on the beginning of year value of the plan's interests in the trust plus actual contributions and allocated investment income (loss) less actual distributions and allocated administrative expenses. Quoted market prices are used to value investments in the trust, with the exception of the GAC. The fair value of certain other investments for which quoted market prices are not available are valued based on yields currently available on

comparable securities of issuers with similar credit ratings. The common/collective trusts are classified within level 2 of the valuation hierarchy.

The preceding methods described may produce a fair value that may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

Prior to the acquisition, the GAC was considered an immediate participation guarantee contract which was not included in the fair value table. In accordance with the plan accounting guidance of the FASB ASC, the cost incurred to purchase the GAC prior to March 20, 1992, was permitted to be carried at contract value, since it is a contract with an insurance company and prior to the acquisition it was excluded from the table above. The cost incurred to fund the GAC after March 20, 1992, was carried at contract value in accordance with the plan accounting guidance of the FASB ASC, since it was a contract that incorporates mortality and morbidity risk. Contract value represents cost plus interest income less distributions for benefits and administrative expenses. To conform to PPL's accounting methods, the John Hancock GAC was classified in the fair value table as a level 3 and as "other" rather than "debt securities" in the asset allocation table for the period ended December 31, 2010.

The following table sets forth, by level within the fair value hierarchy, the plan's assets at fair value at December 31:

	Successor		Predecessor	
	Level 2	Level 3	Level 2	Level 3
Money market funds	$ 2	$ -	$ 2	$ -
Common/collective trusts	213	-	186	-
John Hancock - GAC	-	47	-	-
Total investments at fair value	$ 215	$ 47	$ 188	$ -

The following table sets forth a reconciliation of changes in the fair value of the plan's level 3 assets for the following period:

	Successor
Balance at November 1, 2010	$ -
Purchases	1
Transfers into level 3	46
Balance at December 31, 2010	$ 47

There are no assets categorized as level 1 as of December 31, 2010 and December 31, 2009.

Contributions

KU made discretionary contributions to the pension plan of $13 million in 2010 and 2009. Servco made $9 million and $8 million in discretionary contributions to its pension plan in 2010 and 2009, respectively. The amount of future contributions to the pension plan will depend upon the actual return on plan assets and other factors, but the Company funds its pension obligations in a manner consistent

with the Pension Protection Act of 2006. The Company made contributions totaling $43 million in January 2011.See Note 18, Subsequent Events, for further information.

The Company made contributions to its other postretirement benefit plan of $8 million in 2010 and $7 million in 2009. In 2011, the Company anticipates making voluntary contributions to fund Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Pension Legislation

The Pension Protection Act of 2006 was enacted in August 2006. New rules regarding funding of defined benefit plans are generally effective for plan years beginning in 2008. Among other matters, this comprehensive legislation contains provisions applicable to defined benefit plans which generally (i) mandate full funding of current liabilities within seven years; (ii) increase tax-deduction levels regarding contributions; (iii) revise certain actuarial assumptions, such as mortality tables and discount rates; and (iv) raise federal insurance premiums and other fees for under-funded and distressed plans. The legislation also contains a number of provisions relating to defined-contribution plans and qualified and non-qualified executive pension plans and other matters. The Company's plan met the minimum funding requirements as defined by the Pension Protection Act of 2006 for years ended December 31, 2010 and 2009.

Thrift Savings Plans

KU has a thrift savings plan under section 401(k) of the Internal Revenue Code. Under the plan, eligible employees may defer and contribute to the plan a portion of current compensation in order to provide future retirement benefits. KU makes contributions to the plan by matching a portion of the employees' contributions. The costs of this matching were $3 million in 2010, 2009 and 2008.

KU also makes contributions to RIAs within the thrift savings plans for certain employees not covered by the non-contributory defined benefit pension plan. These employees consist of those hired after December 31, 2005. The Company makes these contributions based on years of service and the employees' wage and salary levels, and makes them in addition to the matching contributions discussed above. The amounts contributed by the Company under this arrangement were less than $1 million in 2010, 2009 and 2008.

Health Care Reform

In March 2010, Health Care Reform (the Patient Protection and Affordable Care Act of 2010) was signed into law. Many provisions of Health Care Reform do not take effect for an extended period of time and many aspects of the law which are currently unclear or undefined will likely be clarified in future regulations.

During 2010, KU recorded an income tax expense of less than $1 million to recognize the impact of the elimination of the tax deduction related to the Medicare Retiree Drug Subsidy that becomes effective in 2013.

Specific provisions within Health Care Reform that may impact KU include:

- Beginning in 2011, requirements extend dependent coverage up to age 26, remove the $2 million lifetime maximum and eliminate cost sharing for certain preventative care procedures.
- Beginning in 2018, a potential excise tax is expected on high-cost plans providing health coverage that exceeds certain thresholds.

The Company has evaluated these provisions of Health Care Reform on its benefit programs in consultation with its actuarial consultants and has determined that the excise tax will not have an impact on its postretirement medical plans. The requirement to extend dependent coverage up to age 26 is not expected to have a significant impact on active or retiree medical costs. The Company will continue to monitor the potential impact of any changes to the existing provisions and implementation guidance related to Health Care Reform on its benefit programs.

Note 10 - Income Taxes

KU’s federal income tax return is included in a United States consolidated income tax return filed by LKE’s direct parent. Prior to October 31, 2010 the return was included in the consolidated return of E.ON US Investments Corp. Due to the acquisition by PPL, the return will be included in the consolidated PPL return beginning November 1, 2010, for each tax period. Each subsidiary of the consolidated tax group, including KU, calculates its separate income tax for each period. The resulting separate-return tax cost or benefit is paid to or received from the parent company or its designee. The Company also files income tax returns in various state jurisdictions. While 2007 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2007-2008 have been received from the IRS, effectively closing these years to additional audit adjustments. Tax years beginning with 2007 were examined under an IRS program, Compliance Assurance Process (“CAP”). This program accelerates the IRS’s review to begin during the year applicable to the return and ends 90 days after the return is filed. KU had no adjustments for the 2007 federal tax return. For 2008, the IRS allowed additional deductions in connection with the Company’s application for a change in repair deductions and disallowed certain bonus depreciation claimed on the original return. The net temporary tax impact for the Company was a $12 million reduction in tax and was recorded in the second quarter of 2010. The 2009 federal return was filed in the third quarter of 2010 and the IRS issued a Partial Acceptance Letter in connection with CAP. The IRS is continuing to review bonus depreciation, storms and other repairs. No net material adverse impact is expected from these remaining areas. The short tax year beginning January 1, 2010 through October 31, 2010, is also being examined under CAP. No material items have been raised by the IRS at this time. The two month period beginning November 1, 2010 and ending December 31, 2010 is not currently under examination.

Additions and reductions of uncertain tax positions during 2010, 2009 and 2008 were less than $1 million. Possible amounts of uncertain tax positions for KU that may decrease within the next 12 months total less than $1 million and are based on the expiration of the audit periods as defined in the statutes. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

The amount KU recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million for the twelve month periods ended and as of December 31, 2010, 2009 and 2008. The interest expense and interest accrued is based on IRS and Kentucky Department of Revenue

large corporate interest rates for underpayment of taxes. At the date of adoption, the Company accrued less than $1 million in interest expense on uncertain tax positions. KU records the interest as “Interest expense” and penalties, if any, as “Operating expenses” on the Statements of Income and “Other current liabilities” on the Balance Sheets, on a pre-tax basis. No penalties were accrued by the Company through December 31, 2010.

Components of income tax expense are shown in the table below:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Current:				
Federal	$ 13	$ 46	$ (5)	$ 46
State	3	9	1	10
Deferred:				
Federal – net	4	20	43	(10)
State – net	-	3	7	(3)
Investment tax credit – deferred	-	-	21	25
Total income tax expense	$ 20	$ 78	$ 67	$ 68

In June 2006, KU and LG&E filed a joint application with the U.S. Department of Energy (“DOE”) requesting certification to be eligible for an investment tax credit applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that KU and LG&E were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, KU received an Order from the Kentucky Commission approving the accounting of the investment tax credit, which includes a full depreciation basis adjustment for the amount of the credit. KU’s portion of the TC2 tax credit is approximately $101 million. Based on eligible construction expenditures incurred, KU recorded an investment tax credit of $21 million and $25 million in 2009 and 2008, respectively, decreasing current federal income taxes. As of December 31, 2009, KU had recorded its maximum credit of $101 million. The income tax expense impact from amortizing this credit over the life of the related property began when the facility was placed in service in January 2011.

In March 2008, certain environmental and preservation groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was in violation of certain environmental laws and demanded relief, including suspension or termination of the program. The plaintiffs voluntarily dismissed their complaint in August 2010.

Components of deferred income taxes included in the Balance Sheets are shown below:

	Successor December 31, 2010		Predecessor December 31, 2009	
Deferred income tax liabilities:				
Depreciation and other plant-related items	$	347	$	303
Regulatory assets and other		133		69
Total deferred income tax liabilities		480		372
Deferred income tax assets:				
Regulatory liabilities and other		80		-
Income taxes due to customers		2		4
Pensions and related benefits		9		17
Liabilities and other		19		18
Total deferred income tax assets		110		39
Net deferred income tax liabilities	$	370	$	333
Balance sheet classification:				
Prepayments and other current assets	$	(6)	$	(3)
Deferred income taxes (non-current)		376		336
Net deferred income tax liabilities	$	370	$	333

The Company expects to have adequate levels of taxable income to realize its recorded deferred income tax assets.

A reconciliation of differences between the income tax expense at the statutory U.S. federal income tax rate and KU's actual income tax expense follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,	
			2009	2008
Statutory federal income tax expense	$ 19	$ 77	$ 70	$ 79
State income taxes – net of federal benefit	2	8	5	5
Qualified production activities deduction	(1)	(4)	(1)	(3)
Dividends received deduction related to EEI investment	-	-	(3)	(8)
Reversal of excess deferred taxes	-	(2)	(2)	(1)
Other differences – net	-	(1)	(2)	(4)
Income tax expense	$ 20	$ 78	$ 67	$ 68
Effective income tax rate	36.4%	35.8%	33.5%	30.1%

The Tax Relief, Unemployment Reauthorization and Job Creation Act of 2010, enacted December 17, 2010 provided, among other provisions, certain incentives related to bonus depreciation and 100% expensing of qualifying capital expenditures. KU benefited from these new provisions by reducing its 2010 current federal income tax expense. This reduction in federal taxable income for KU does, however, result in a reduction of KU's Section 199 Manufacturing deduction, which is based on manufacturing taxable income and correspondingly increases income tax expense. The impact from these changes on 2010 was not material; however, KU anticipates a significant reduction of taxable income in 2011 and 2012 and a corresponding loss of most, if not all, of the Section 199 Manufacturing deduction for the following two years.

Note 11 - Long-Term Debt

As summarized below, at December 31, 2010, long-term debt consisted of first mortgage bonds and secured pollution control bonds. At December 31, 2009, long-term debt and the current portion of long-term debt consisted primarily of pollution control bonds and long-term loans from affiliated companies.

	Successor 2010	Predecessor 2009
Current portion of long-term debt to affiliates	$ -	$ 33
Long-term debt to affiliated companies	-	1,298
Secured first mortgage bonds, net of debt discount and amortization of debt discount	1,500	-
Pollution control revenue bonds, collateralized by first mortgage bonds	351	351
Fair value adjustment from purchase accounting	1	-
Unamortized discount	(11)	-
Total long-term debt	1,841	1,682
Less current portion	-	261
Long-term debt, excluding current portion	$ 1,841	$ 1,421

	Stated Interest Rates	Maturities	Debt Amounts
Successor			
Outstanding at December 31, 2010:			
Current portion	N/A	N/A	$ -
Non-current portion	Variable – 6.00%	2015-2040	1,841
Predecessor			
Outstanding at December 31, 2009:			
Current portion	Variable – 4.240%	2010-2034	$ 261
Non-current portion	Variable – 7.035%	2011-2037	1,421

As of December 31, 2009, long-term debt includes $228 million of pollution control bonds that were classified as current portion because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include Carroll County 2002 Series A and B, 2004 Series A, 2006 Series B and 2008 Series A; Muhlenberg County 2002 Series A; and Mercer County 2000 Series A and 2002 Series A. Maturity dates for these bonds range from 2023 to 2034. As of December 31, 2009, the bonds were classified as current portion of long-term debt because investors could put the bonds back to the Company within one year. As of December 31, 2010, the bonds were reclassified as long-term debt. See Note 1, Summary of Significant Accounting Policies, for changes in classification.

Pollution control bonds are obligations of KU issued in connection with tax-exempt pollution control bonds by various counties in Kentucky. A loan agreement obligates the Company to make debt service payments to the counties in amounts equal to the debt service due from the counties on the related pollution control bonds. Depending on the type of expense, the Successor capitalized debt expenses in long-term other regulatory assets or long-term other assets to align with the term of the debt for which the

expenses were related. The Predecessor capitalized debt expenses in current or long-term other regulatory assets or other current or long-term other assets based on the amount of expense expected to be recovered within the next year through rate recovery. Both Predecessor and Successor amortized debt expenses over the lives of the related bond issues. The Predecessor presentation and the Successor presentation are both appropriate under regulatory practices and GAAP.

In October 2010, in order to secure their respective obligations with respect to the pollution control bonds, KU issued first mortgage bonds to the pollution control bond trustees. KU's first mortgage bonds contain terms and conditions that are substantially parallel to the terms and conditions of the counties' debt, but provide that obligations are deemed satisfied to the extent of payments under the related loan agreement, and thus generally require no separate payment of principal and interest except under certain circumstances, including should KU default on the respective loan agreement. Also in October 2010, one national rating agency revised downward the short-term credit rating of the pollution control bonds and the Company's issuer rating as a result of the pending acquisition by PPL.

Several series of KU's pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At December 31, 2010, KU had an aggregate $351 million of outstanding pollution control indebtedness, of which $96 million is in the form of insured auction rate securities wherein interest rates are reset every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. Since 2008, interest rates increased and the Company experienced "failed auctions" when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture.

The average annualized interest rates on the auction rate bonds follow:

Successor	Predecessor	
November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	December 31, 2009
0.53%	0.51%	0.44%

The instruments governing this auction rate bond permit KU to convert the bond to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently.

As a result of downgrades of the monoline insurers by all of the rating agencies to levels below that of the Company's rating, the debt ratings of the Company's insured bonds are all based on the Company's senior secured debt rating and are not influenced by the monoline bond insurer ratings.

In connection with the PPL acquisition, on November 1, 2010, KU borrowed $1,331 million from a PPL subsidiary, in order to repay loans from a subsidiary of E.ON. KU used the net proceeds received from the sale of the first mortgage bonds to repay the debt owed to the PPL subsidiary arising from the borrowing.

In November 2010, KU issued first mortgage bonds totaling $1,500 million and used the proceeds to repay the loans from a PPL subsidiary mentioned above and for general corporate purposes. The first mortgage bonds were issued at a discount as described in the table below:

First Mortgage Bonds	Principal	Discount Price	First Mortgage Bonds Proceeds (a)
Series due 2015	$ 250	99.650%	$ 249
Series due 2020	500	99.622%	498
Series due 2040	750	98.915%	742
Total	$ 1,500		$ 1,489

(a) Before expenses other than discount to Purchaser

The first mortgage bonds were issued by KU in accordance with the rules of Section 144A of the Securities Act of 1933. KU has entered into a registration rights agreement in which it has agreed to file a registration statement with the SEC relating to an offer to exchange the first mortgage bonds for publicly tradable securities having substantially identical terms. If ultimate registration and/or certain milestones are not completed by certain dates in mid- and late 2011, the Company has agreed to pay liquidated damages to the bondholders. The liquidated damages would total 0.25% per annum of the principal amount of the bonds for the first 90 days and 0.50% per annum of the principal amount thereafter until the conditions described above have been cured.

There were no redemptions or maturities of long-term debt for 2009. Redemptions and maturities of long-term debt for 2010 are summarized below:

Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
Successor					
2010	Due to PPL Investment Corp.	$ 1,331	4.24%-7.035%	Unsecured	2010-2037
2010	Due to E.ON affiliates	1,331	4.24%-7.035%	Unsecured	2010-2037

Issuances of long-term debt for 2010 and 2009 are summarized below:

Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
Successor					
2010	Due to PPL Investment Corp.	$ 1,331	4.24%-7.035%	Unsecured	2010-2037
2010	First mortgage bonds	250	1.625%	Secured	2015
2010	First mortgage bonds	500	3.25%	Secured	2020
2010	First mortgage bonds	750	5.125%	Secured	2040
Predecessor					
2009	Due to E.ON affiliates	50	4.445%	Unsecured	2019
2009	Due to E.ON affiliates	50	4.81%	Unsecured	2019
2009	Due to E.ON affiliates	50	5.28%	Unsecured	2017

As of December 31, 2010, all of the Company's long-term debt is secured by a first mortgage lien on substantially all of the real and tangible personal property of the Company located in Kentucky.

Long-term debt maturities for KU are shown in the following table:

2011	$ -
2012	-
2013	-
2014	-
2015	250
Thereafter	1,601
	$ 1,851

KU was in compliance with all debt covenants at December 31, 2010.

See Note 1, Summary of Significant Accounting Policies, for certain debt refinancing and associated transactions completed by KU in connection with the PPL acquisition, Note 2, Acquisition by PPL, for the adjustment made to the pollution control bonds to reflect fair value and Note 15, Related Party Transactions, for long-term debt payable to affiliates.

Note 12 - Notes Payable and Other Short-Term Obligations

Intercompany Revolving Line of Credit

KU participates in an intercompany money pool agreement wherein LKE and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) of up to $400 million. Details of the balances are as follows:

	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2010, Successor	$ 400	$ 10	$ 390	0.25%
December 31, 2009, Predecessor	400	45	355	0.20%

LKE maintains revolving credit facilities totaling $300 million at December 31, 2010 and $313 million at December 31, 2009, to ensure funding availability for the money pool. At December 31, 2010, the LKE facility is with PPL Investment Corp. LKE pays PPL Investment Corp. an annual commitment fee based on the Utilities' current bond ratings on the unused portion of the commitment. At December 31, 2009, one facility, totaling $150 million, was with E.ON North America, Inc., while the remaining line, totaling $163 million, was with Fidelia, both affiliated companies of E.ON. The balances are as follows:

	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2010, Successor	$ 300	$ -	$ 300	N/A
December 31, 2009, Predecessor	313	276	37	1.25%

Bank Revolving Line of Credit

As of December 31, 2010, the Company maintained a $400 million revolving line of credit with a group of banks maturing in December 2014. The revolving line of credit allows KU to issue letters of credit or borrow funds up to $400 million. Outstanding letters of credit reduce the facility's available borrowing capacity. The Company pays the banks an annual commitment fee based on current bond ratings on the unused portion of the commitment. At December 31, 2010, there was no amount borrowed under this facility although letters of credit totaling $198 million have been issued under this facility. This credit agreement contains financial covenants requiring the borrower's debt to total capitalization ratio to not exceed 70%, as calculated pursuant to the credit agreement, and other customary covenants.

As of December 31, 2009, the Company maintained a $35 million bilateral line of credit with an unaffiliated financial institution maturing in June 2012. The Company paid the banks an annual commitment fee on the unused portion of the commitment. At December 31, 2009, there was no balance outstanding under this facility. This facility was terminated on November 1, 2010, in conjunction with the PPL acquisition.

On December 1, 2010, KU replaced the letters of credit issued under prior letter of credit facilities with letters of credit of the same amount issued under the revolving line of credit. The four letter of credit facilities were subsequently terminated.

KU was in compliance with all line of credit covenants at December 31, 2010.

See Note 1, Summary of Significant Accounting Policies, for certain debt refinancing and associated transactions completed by KU in connection with the PPL acquisition and Note 15, Related Party Transactions, for long-term debt payable to affiliates.

Note 13 - Commitments and Contingencies

Operating Leases

KU leases office space, office equipment, plant equipment, real estate, railcars, telecommunications and vehicles and accounts for these leases as operating leases. In addition, KU reimburses LG&E for a portion of the lease expense paid by LG&E for KU's usage of office space leased by LG&E. Total lease expense was $10 million, $10 million and $9 million for 2010, 2009 and 2008, respectively. The future minimum annual lease payments for operating leases for years subsequent to December 31, 2010, are shown in the following table:

2011	$	8
2012		7
2013		5
2014		5
2015		3
Thereafter		1
	$	29

Owensboro Contract Litigation and Termination

In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. In May 2009, KU and OMU executed a settlement agreement resolving the matter on a basis consistent with prior court rulings and KU has received the agreed settlement amounts. Pursuant to the settlement's operation, the OMU Agreement terminated in May 2010.

Sale and Leaseback Transaction

The Company is a participant in a sale and leaseback transaction involving its 62% interest in two jointly owned CTs at KU's E.W. Brown generating station (Units 6 and 7). Commencing in December 1999, KU and LG&E entered into a tax-efficient, 18-year lease of the CTs. The Utilities have provided funds to fully defease the lease and have executed an irrevocable notice to exercise an early purchase option contained in the lease after 15.5 years. The financial statement treatment of this transaction is no different than if the Utilities had retained its ownership interest. The leasing transaction was entered into following receipt of required state and federal regulatory approvals. At December 31, 2010, the Balance Sheets included these assets at a value of $65 million, which is reflected in "Regulated utility plant – electric."

In case of default under the lease, the Company is obligated to pay to the lessor its share of certain fees or amounts. Primary events of default include loss or destruction of the CTs, failure to insure or maintain the CTs and unwinding of the transaction due to governmental actions. No events of default currently exist with respect to the lease. Upon any termination of the lease, whether by default or expiration of its term, title to the CTs reverts jointly to KU and LG&E.

At December 31, 2010, the maximum aggregate amount of default fees or amounts was $7 million, of which KU would be responsible for 62% (approximately $4 million). The Company has made arrangements with LKE, via guarantee and regulatory commitment, for LKE to pay its full portion of any default fees or amounts.

Letters of Credit

KU has provided letters of credit as of December 31, 2010 and 2009, for on-balance sheet obligations totaling $198 million to support bonds of $195 million and letters of credit for off-balance sheet obligations totaling less than $1 million to support certain obligations related to workers' compensation.

Commodity Purchases

OVEC

KU has a contract for power purchases with OVEC, terminating in 2026, for various Mw capacities. KU holds a 2.5% investment interest in OVEC with ten other electric utilities. KU is not the primary beneficiary; therefore, the investment is not consolidated into the Company's financial statements, but is recorded on the cost basis. OVEC is located in Piketon, Ohio, and owns and operates two coal-fired power plants, Kyger Creek Station in Ohio, and Clifty Creek Station in Indiana. KU is contractually entitled to 2.5% of OVEC's output, approximately 60 Mw of nameplate generation capacity. Pursuant to

the OVEC power purchase contract, the Company may be conditionally responsible for a 2.5% pro-rata share of certain obligations of OVEC under defined circumstances. These contingent liabilities may include unpaid OVEC indebtedness as well as shortfall amounts in certain excess decommissioning costs and postretirement benefits other than pension. KU's contingent potential proportionate share of OVEC's December 31, 2010 outstanding debt was $35 million. Future obligations for power purchases from OVEC are demand payments, comprised of annual minimum debt service payments, as well as contractually required reimbursement of plant operating, maintenance and other expenses, and are shown in the following table:

2011	$ 9
2012	10
2013	10
2014	10
2015	10
Thereafter	114
	$ 163

Coal and Natural Gas Transportation Purchase Obligations

KU has contracts to purchase coal and natural gas transportation. Future obligations are shown in the following table:

2011	$ 439
2012	200
2013	144
2014	93
2015	91
Thereafter	14
	$ 981

Construction Program

KU had approximately $116 million of commitments in connection with its construction program at December 31, 2010.

In June 2006, KU entered into a construction contract regarding the TC2 project. The contract is generally in the form of a turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price. During 2009 and 2010, KU received several contractual notices from the TC2 construction contractor asserting historical force majeure and excusable event claims for a number of adjustments to the contract price, construction schedule, commercial operations date, liquidated damages or other relevant provisions. In September 2010, KU and the construction contractor agreed to a settlement to resolve the force majeure and excusable event claims occurring through July 2010, under the TC2 construction contract, which settlement provided for a limited, negotiated extension of the contractual commercial operations date and/or relief from liquidated damage calculations. With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand

since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. KU cannot currently estimate the ultimate outcome of these matters.

TC2 Air Permit

The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the KDAQ in November 2005. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an Order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the two EPA objections. In March 2010, the Sierra Club submitted a petition to the EPA to object to the permit revision, which is now pending before the EPA. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the EPA issues a final ruling on the pending petition and all applicable appeals have been exhausted, the Company cannot predict the final outcome of this matter.

Environmental Matters

The Company's operations are subject to a number of environmental laws and regulations in each of the jurisdictions in which it operates governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety. As indicated below and summarized at the conclusion of this section, evolving environmental regulations will likely increase the level of capital and operating and maintenance expenditures incurred by the Company during the next several years. Based upon prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

Ambient Air Quality

The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS

through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which required additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provided for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR.

In July 2008, a federal appeals court issued a ruling finding deficiencies in the CAIR and vacating it. In December 2008, the Court amended its previous Order, directing the EPA to promulgate a new regulation but leaving the CAIR in place in the interim. The remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and the Utilities' compliance plans relating thereto due to the interconnection of the CAIR with such associated programs.

In January 2010, the EPA proposed a revised NAAQS for ozone which would increase the stringency of the standard. In addition, the EPA published final revised NAAQS standards for NO_2 and SO_2 in February 2010 and June 2010, respectively, which are more stringent than previous standards. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the revised NAAQS standards, KU's power plants are potentially subject to requirements for additional reductions in SO_2 and NOx emissions.

In July 2010, the EPA issued the proposed CATR, which serves to replace the CAIR. The CATR provides for a two-phase SO_2 reduction program with Phase I reductions due by 2012 and Phase II reductions due by 2014. The CATR provides for NOx reductions in 2012, but the EPA advised that it is studying whether additional NOx reductions should be required for 2014. The CATR is more stringent than the CAIR as it accelerates certain compliance dates and provides for only intrastate and limited interstate trading of emission allowances. In addition to its preferred approach, the EPA is seeking comment on an alternative approach which would provide for individual emission limits at each power plant. The EPA has announced that it will propose additional "transport" rules to address compliance with revised NAAQS standards for ozone and particulate matter which will be issued by the EPA in the future, as discussed below.

Hazardous Air Pollutants

As provided in the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provided for reductions of

70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a “co-benefit” of the controls installed for purposes of compliance with the CAIR.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The EPA has entered into a consent decree requiring it to promulgate a utility Maximum Achievable Control Technology rule to replace the CAMR with a proposed rule due by March 2011 and a final rule by November 2011. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new rules with different or more stringent requirements for reduction of mercury and other hazardous air pollutants. Kentucky has also repealed its corresponding state mercury regulations.

Acid Rain Program

The Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to “acid rain” conditions in the northeastern U.S. The Clean Air Act also contains requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze

The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its Clean Air Visibility Rule detailing how the Clean Air Act’s BART requirements will be applied to facilities, including power plants built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR provided for more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPs incorporate certain CAIR requirements, the remand of the CAIR could potentially impact regional haze SIPs. See “Ambient Air Quality” above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls

Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. KU met its Phase I SO_2 requirements primarily through installation of FGD equipment on Ghent Unit 1. KU’s strategy for its Phase II SO_2 requirements, which commenced in 2000, includes the installation of additional FGD equipment, as well as using accumulated emission allowances and fuel switching to defer certain additional capital expenditures and continue to evaluate improvements to further reduce SO_2 emissions. KU believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. KU’s compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. KU will

continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. KU expects to incur additional capital expenditures currently approved in its ECR plans totaling approximately $500 million during the 2011 through 2013 time period to achieve emissions reductions and manage coal combustion residuals. Monthly recovery is subject to periodic review by the Kentucky Commission.

GHG Developments

In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. As discussed below, legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs, including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are on-going. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark, in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. In Copenhagen, the U.S. made a nonbinding commitment to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations met in Cancun, Mexico, in December 2010 to continue negotiations toward a binding agreement.

GHG Legislation

KU is monitoring on-going efforts to enact GHG reduction requirements and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, which was a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. The bill provided for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020 and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would have initially been allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would have also established a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contained additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency.

In September 2009, the Clean Energy Jobs and American Power Act, which was largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raised the emissions reduction target for 2020 to 20% below 2005 levels and did not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision incorporated allowance allocation provisions similar to the House bill. Although Senators Kerry and Lieberman and others worked to reach a consensus on GHG legislation, no bill passed the Senate in 2010. The Company is closely monitoring the progress of pending energy legislation, but the prospect for passage of comprehensive GHG legislation in 2011 is uncertain.

GHG Regulations

In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. In April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities are required to submit annual reports commencing with calendar year 2010. In May 2010, the EPA issued a final GHG "tailoring" rule, effective January 2011, requiring new or modified sources with GHG emissions equivalent to at least 75,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the rule. The final rule will apply to new and modified power plants beginning in January 2011. The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations. In December 2010, the EPA announced that it plans to promulgate GHG New Source Performance Standards for power plants, including both new and existing facilities. A proposed rule is expected by July 2011, while a final rule is expected by May 2012. In the absence of either a proposed or final regulation, KU is unable to assess the potential impact of any future regulation.

GHG Litigation

A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, a three judge panel of the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. In March 2010, the court vacated the opinion of the three-judge panel and granted a motion for rehearing but subsequently denied the appeal due to the lack of a quorum. The appellate ruling leaves in effect the lower court ruling dismissing the plaintiffs' claims. In January 2011, the Supreme Court denied petitioner's petition for review, which effectively brings the case to an end. The Comer complaint alleged that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. E.ON, the former indirect parent of the Utilities, was named as a defendant in the complaint but was not a party to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. KU continues to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to operations.

Ghent Opacity NOV

In September 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July of 2007 at Units 1 and 3 of KU's Ghent generating station. The parties have met on this matter and KU has received no further communications from the EPA. The Company is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

Ghent New Source Review NOV

In March 2009, the EPA issued an NOV alleging that KU violated certain provisions of the Clean Air Act's rules governing new source review and prevention of significant deterioration by installing FGD and SCR controls at its Ghent generating station without assessing potential increased sulfuric acid mist emissions. KU contends that the work in question, as pollution control projects, was exempt from the requirements cited by the EPA. In December 2009, the EPA issued a Section 114 information request seeking additional information on this matter. In March 2010, the Company received an EPA settlement proposal providing for imposition of additional permit limits and emission controls and anticipates continued settlement negotiations with the EPA. Negotiations between the EPA and KU are ongoing. Depending on the provisions of a final settlement or the results of litigation, if any, resolution of this matter could involve significant increased operating and capital expenditures. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination on the Company's financial position or results of operations.

Ash Ponds and Coal-Combustion Byproducts

The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the TVA's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including KU, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of KU's impoundments, which the EPA found to be in satisfactory condition. In June 2010, the EPA published proposed regulations for coal combustion byproducts handled in landfills and ash ponds. The EPA has proposed two alternatives: (1) regulation of coal combustion byproducts in landfills and ash ponds as a hazardous waste or (2) regulation of coal combustion byproducts as a solid waste with minimum national standards. Under both alternatives, the EPA has proposed safety requirements to address the structural integrity of ash ponds. In addition, the EPA will consider potential refinements of the provisions for beneficial reuse of coal combustion byproducts.

Water Discharges and PCB Regulations

The EPA has also announced plans to develop revised effluent limitation guidelines governing discharges from power plants and standards for cooling water intake structures. The EPA has further announced plans to develop revised standards governing the use of polychlorinated biphenyls ("PCB") in electrical equipment. The Company is monitoring these ongoing regulatory developments but will be unable to determine the impact until such time as new rules are finalized.

Impact of Pending and Future Environmental Developments

As a company with significant coal-fired generating assets, KU will likely be substantially impacted by pending or future environmental rules or legislation requiring mandatory reductions in GHG emissions or other air emissions, imposing more stringent standards on discharges to waterways, or establishing additional requirements for handling or disposal of coal combustion byproducts. These evolving environmental regulations will likely require an increased level of capital expenditures and increased incremental operating and maintenance costs by the Company over the next several years. Due to the uncertain nature of the final regulations that will ultimately be adopted by the EPA, including the

reduction targets and the deadlines that will be applicable, the Company cannot finalize estimates of the potential compliance costs, but should the final rules incorporate additional emission reduction requirements, require more stringent emissions controls or implement more stringent byproducts storage and disposal practices, such costs will likely be significant. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based upon a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Capital expenditures for KU associated with such actions are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary. With respect to potential developments in water discharge, revised PCB standards or GHG initiatives, costs in such areas cannot be estimated due to the preliminary status or uncertain outcome of such developments, but would be in addition to the above amount and could be substantial. Ultimately, the precise impact on the Company's operations of these various environmental developments cannot be determined prior to the finalization of such requirements. Based upon prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

TC2 Water Permit

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County generating station. In October 2010, the hearing officer issued a report and recommended Order providing for dismissal of the claims raised by the petitioners. In December 2010, the Secretary issued a final Order dismissing all claims and upholding the permit which petitioners subsequently appealed to Trimble County Circuit Court.

General Environmental Proceedings

From time to time, KU appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include a prior Section 114 information request from the EPA relating to new-source review issues at KU's Ghent unit 2; completed settlement with state regulators regarding compliance with particulate limits in the air permit for KU's Tyrone generating station; remediation obligations or activities for or other risks relating to elevated PCB levels at existing properties; liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites; and on-going claims regarding the GHG emissions from the Company's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the Company's operations.

Note 14 - Jointly Owned Electric Utility Plant

TC2 is a jointly owned unit at the Trimble County site. KU and LG&E own undivided 60.75% and 14.25% interests, respectively. Of the remaining 25%, IMEA owns a 12.12% undivided interest and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate share of capital cost during construction and fuel, operation and maintenance cost when TC2 is in-service. With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. In December 2009 and June 2008, LG&E sold assets to KU related to the construction of TC2 with a net book value of $48 million and $10 million, respectively.

The following data represent shares of the jointly owned property (capacity based on nameplate rating):

	TC2				
	KU	LG&E	IMPA	IMEA	Total
Ownership interest	60.75%	14.25%	12.88%	12.12%	100%
Mw capacity	509	119	108	102	838

KU's 60.75% ownership:		LG&E's 14.25% ownership:	
Plant held for future use	$ 62	Plant held for future use	$ 2
Construction work in progress	703	Construction work in progress	187
Accumulated depreciation	(1)	Accumulated depreciation	-
Net book value	$ 764	Net book value	$ 189

KU and LG&E jointly own the following CTs and related equipment (capacity based on net summer capability) as of December 31, 2010:

	KU				LG&E				Total			
Ownership Percentage	Mw Capacity	Cost	Depr.	Net Book Value	Mw Capacity	Cost	Depr.	Net Book Value	Mw Capacity	Cost	Depr.	Net Book Value
KU 47%, LG&E 53% (a)	129	$ 43	$ -	$ 43	146	$ 48	$ -	$ 48	275	$ 91	$ -	$ 91
KU 62%, LG&E 38% (b)	190	64	(2)	62	118	40	(2)	38	308	104	(4)	100
KU 71%, LG&E 29% (c)	228	63	(1)	62	92	26	-	26	320	89	(1)	88
KU 63%, LG&E 37% (d)	404	109	(1)	108	236	64	(1)	63	640	173	(2)	171
KU 71%, LG&E 29% (e)	n/a	4	-	4	n/a	2	-	2	n/a	6	-	6

(a) Comprised of Paddy's Run 13 and E.W. Brown 5. In addition to the above jointly owned utility plant, there is an inlet air cooling system attributable to unit 5 and units 8-11 at the E.W. Brown facility. This inlet air cooling system is not jointly owned, however, it is used to increase production on the units to which it relates, resulting in an additional 88 Mw of capacity for KU.

(b) Comprised of units 6 and 7 at the E.W. Brown facility.
(c) Comprised of units 5 and 6 at the Trimble County facility.
(d) Comprised of CT Substation 7-10 and units 7, 8, 9 and 10 at the Trimble County facility.
(e) Comprised of CT Substation 5 and 6 and CT Pipeline at the Trimble County facility.

Both KU's and LG&E's participating share of direct expenses of the jointly owned plants is included in the corresponding operating expenses on each company's respective Statements of Income (i.e., fuel, maintenance of plant, other operating expense).

Note 15 - Related Party Transactions

KU and subsidiaries of LKE and PPL engage in related party transactions. Transactions between KU and LKE subsidiaries are eliminated on consolidation of LKE. Transactions between KU and PPL subsidiaries are eliminated on consolidation of PPL. These transactions are generally performed at cost and are in accordance with FERC regulations under PUHCA 2005 and the applicable Kentucky Commission and Virginia Commission regulations.

Intercompany Wholesale Sales and Purchases

KU and LG&E jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are recorded as intercompany wholesale sales and purchases are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the Utilities. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

These sales and purchases are included in the Statements of Income as "Operating revenues", "Power purchased" expenses and "Other operation and maintenance expenses". KU's intercompany electric revenues and power purchased expenses were as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Electric operating revenues from LG&E	$ 2	$ 13	$ 21	$ 80
Power purchased and related operations and maintenance expenses from LG&E	21	79	101	109

Interest Charges

See Note 11, Long-Term Debt, and Note 12, Notes Payable and Other Short-Term Obligations, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

KU's interest expense to affiliated companies was as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Interest on money pool loans	$ -	$ -	$ -	$ 2
Interest on PPL loans	2	-	-	-
Interest on Fidelia loans	-	62	69	56

Interest paid to LKE on the money pool arrangement was less than $1 million for 2010 and 2009.

Dividends

In September 2010, the Company paid dividends of $50 million to its sole shareholder, LKE.

Capital Contributions

The Company received no capital contributions in 2010, but received capital contributions of $75 million and $145 million from its sole shareholder, LKE, in 2009 and 2008, respectively.

Sale of Assets

In 2010, KU sold and bought assets of less than $1 million to and from LG&E. In December 2009, LG&E sold assets to KU related to the construction of TC2 with a net book value of $48 million.

Other Intercompany Billings

Servco provides the Company with a variety of centralized administrative, management and support services. Associated charges include payroll taxes paid by Servco on behalf of KU, labor and burdens of Servco employees performing services for KU, coal purchases and other vouchers paid by Servco on behalf of KU. The cost of these services is directly charged to the Company, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and/or other statistical information. These costs are charged on an actual cost basis.

In addition, the Utilities provide services to each other and to Servco. Billings between the Utilities relate to labor and overheads associated with union and hourly employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from KU to Servco include cash received by Servco on behalf of KU, tax settlements and other payments

made by the Company on behalf of other non-regulated businesses which are reimbursed through Servco.

Intercompany billings to and from KU were as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Servco billings to KU	$ 46	$ 233	$ 169	$ 227
LG&E billings to KU	14	49	44	5
KU billings to Servco	12	11	14	3
KU billings to LG&E	-	-	78	75

Intercompany Balances

The Company had the following balances with its affiliates:

	Successor	Predecessor
	December 31, 2010	December 31, 2009
Accounts receivable from LKE	$ 12	$ 9
Accounts payable to LG&E	22	53
Accounts payable to Servco	23	20
Accounts payable to Fidelia	-	15
Notes payable to LKE	10	45
Long-term debt to Fidelia	-	1,331

Note 16 - Selected Quarterly Data (Unaudited)

	For the 2010 Periods Ended (a)				
	Predecessor				Successor
	March 31	June 30	September 30	October 31	December 31
Operating revenues	$ 380	$ 350	$ 416	$ 102	$ 263
Operating income	87	71	105	22	65
Net income	44	31	54	11	35

(a) Periods ended March 31, June 30 and September 30 represent three months then ended. Period ended October 31 represents one month then ended and period ended December 31 represents two months then ended.

	For the 2009 Quarters Ended			
	Predecessor			
	March 31	June 30	September 30	December 31
Operating revenues	$ 363	$ 305	$ 341	$ 346
Operating income	19	53	125	72
Net income	7	26	66	34

Note 17 - Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consisted of the following:

	Pre-Tax Accumulated Derivative Gain (Loss)	Income Taxes	Net
Balance at December 31, 2009, Predecessor	$ -	$ -	$ -
Equity investee's other comprehensive income (loss)	(3)	1	(2)
Balance at October 31, 2010, Predecessor	(3)	1	(2)
Effect of PPL acquisition	3	(1)	2
Balance at December 31, 2010, Successor	$ -	$ -	$ -

Note 18 - Subsequent Events

Subsequent events have been evaluated through February 25, 2011, the date of issuance of these statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

On January 31, 2011, KU filed a notice of intent to file a rate case with the Virginia Commission for the test year ended December 31, 2010. The case is expected to be filed on or after April 1, 2011.

With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. LG&E and KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages.

On January 14, 2011, KU contributed $43 million to its pension plan.

pwc

Report of Independent Auditors

To Stockholder of Kentucky Utilities Company

In our opinion, the accompanying balance sheet and the related statements of income, retained earnings, comprehensive income, cash flows, and capitalization present fairly, in all material respects, the financial position of Kentucky Utilities Company (Successor Company) at December 31, 2010 and the results of its operations and its cash flows for the period from November 1, 2010 to December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assertion of the effectiveness of internal control over financial reporting, included in "Management's Report of Internal Controls Over Financial Reporting" which appears on page 50. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audit. We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States) and in accordance with the auditing and attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

As discussed in Note 2 to the financial statements, on November 1, 2010, PPL Corporation completed its acquisition of LG&E and KU Energy LLC and its subsidiaries. The push-down basis of accounting was used at the acquisition date.

A company's internal control over financial reporting is a process effected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and those charged with governance and (iii) provide reasonable assurance regarding prevention or timely detection and correction of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect and correct misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Louisville, Kentucky
February 25, 2011

Report of Independent Auditors

To Stockholder of Kentucky Utilities Company

In our opinion, the accompanying balance sheet and the related statements of income, retained earnings, comprehensive income, cash flows, and capitalization present fairly, in all material respects, the financial position of Kentucky Utilities Company (Predecessor Company) at December 31, 2009 and the results of its operations and its cash flows for the period from January 1, 2010 to October 31, 2010 and for each of the two years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the financial statements, on November 1, 2010, PPL Corporation completed its acquisition of LG&E and KU Energy LLC and its subsidiaries. The push-down basis of accounting was used at the acquisition date.

PricewaterhouseCoopers LLP

Louisville, Kentucky
February 25, 2011

Supplement, dated December 1, 2010 to Reoffering Circular dated December 10, 2008, as supplemented as of December 16, 2008 and October 29, 2010 (the "Reoffering Circular")

$50,000,000
County of Carroll, Kentucky
Environmental Facilities Revenue Bonds, 2004 Series A
(Kentucky Utilities Company Project)

Effective as of December 1, 2010, through December 1, 2011 (the Letter of Credit (as defined below) expiration date, subject to extension or earlier termination), payment of the principal of and interest on the above-referenced bonds (the "Bonds") when due will be paid with funds drawn under an irrevocable transferable direct pay letter of credit (the "Letter of Credit") issued by

WELLS FARGO BANK, NATIONAL ASSOCIATION

The Letter of Credit will permit the Trustee to draw with respect to the Bonds up to an amount sufficient to pay (i) the principal thereof (or that portion of the purchase price corresponding to principal) plus (ii) interest thereon (or that portion of the purchase price corresponding to interest) at an assumed rate of 14% per annum for at least 45 days.

The Bonds will continue to bear interest at a Weekly Rate, determined by the Remarketing Agent in accordance with the Indenture, payable on the first Business Day of each calendar month, commencing on January 3, 2011. The interest rate period, interest rate and Interest Rate Mode will be subject to change under certain conditions, as described in the Reoffering Circular. The Bonds are subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption following a determination of taxability prior to maturity, as described in the Reoffering Circular. The Bonds are subject to mandatory purchase on any date on which the Bonds are converted to a different Interest Rate Mode and upon the expiration of the Letter of Credit or any Alternate Credit Facility.

This supplement contains a description of the Letter of Credit and Wells Fargo Bank, National Association, the issuer of the Letter of Credit. For purposes of the Reoffering Circular, the Letter of Credit is a "Credit Facility" and Wells Fargo Bank, National Association is a "Credit Facility Issuer." Except as otherwise specified herein, information in the Reoffering Circular referred to above has not been amended or modified and the information contained herein is qualified by reference to, and should be read in conjunction with, the Reoffering Circular, including information incorporated therein by reference. Terms not otherwise defined herein shall have the meanings ascribed to them in such Reoffering Circular.

The eighth paragraph under the section of the Reoffering Circular captioned "Introductory Statement" is hereby amended to read in its entirety as follows:

Effective December 1, 2010, the Company will cause to be delivered an irrevocable transferable direct pay letter of credit (the "Letter of Credit"), issued by Wells Fargo Bank, National Association (the "Bank"), to provide for the timely payment of principal of and accrued interest (calculated for at least 45 days at the maximum rate of 14% per annum) on, and purchase price of, the Bonds. The Company will be required to reimburse the Bank for all amounts drawn by the Trustee under the Letter of Credit pursuant to the terms of a certain letter agreement, to be dated as of December 1, 2010 (the "Reimbursement Agreement"), between the Company and the Bank. The Letter of Credit will expire on December 1, 2011, unless extended or earlier terminated.

* * * *

The section of the Reoffering Circular captioned "The Letter of Credit" is hereby amended to read in its entirety as follows:

THE LETTER OF CREDIT

The following summarizes certain provisions of the Letter of Credit and the Reimbursement Agreement, to which reference is made for the detailed provisions thereof. Unless otherwise defined in this Reoffering Circular, capitalized terms in the following summary are used as defined in the Letter of Credit and the Reimbursement Agreement. The Company is permitted under the Indenture to deliver an Alternate Credit Facility to replace the Letter of Credit. Any such Alternate Credit Facility must meet certain requirements described in the Indenture.

The Letter of Credit

The Letter of Credit will be an irrevocable transferable direct pay letter of credit issued by the Bank in order to provide additional security for the payment of principal of, purchase

price of, interest on and premium, if applicable, on any date when payments under the Bonds are due, including principal and interest payments and payments upon tender, redemption, acceleration or maturity of the Bonds. The Letter of Credit will provide for direct payments to or upon the order of the Trustee as set forth in the Letter of Credit in amounts sufficient to pay such amounts in accordance with the terms thereof.

The Letter of Credit will be issued in an amount equal to the aggregate principal amount of the outstanding Bonds, plus an amount that represents interest accrued thereon at an assumed rate of 14% per annum for 45 days (the "Credit Amount"). The Trustee, upon compliance with the terms of the Letter of Credit, is authorized to draw up to (a) an amount sufficient (i) to pay principal of the Bonds, when due, whether at maturity or upon redemption or acceleration, and (ii) to pay the portion of the purchase price of the Bonds delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed (a "Liquidity Drawing") equal to the principal amount of the Bonds, plus (b) an amount not to exceed 45 days of accrued interest on such Bonds at an assumed rate of 14% per annum (i) to pay interest on the Bonds, when due, and (ii) to pay the portion of the interest accrued on the Bonds as of any Liquidity Drawing.

The amount available under the Letter of Credit will be automatically reduced by the amount of any drawing thereunder, subject to reinstatement as described below. With respect to a drawing by the Trustee solely to pay interest on the Bonds on an Interest Payment Date, the amount available under the Letter of Credit will be automatically reinstated in the amount of such drawing effective on the earlier of (i) receipt by the Bank from the Company of reimbursement of any drawing solely to pay interest in full or (ii) at the opening of business on the eleventh calendar day after the date the Bank honors such drawing, unless the Trustee has received written notice from the Bank by the tenth calendar day after the date the Bank honors such drawing the Bank is not so reinstating the available amount due to the Company's failure to reimburse the Bank for such drawing in full, or that an event of default has occurred and is continuing under the Reimbursement Agreement and, in either case, directing, an acceleration of the Bonds pursuant to the Indenture. With respect to a Liquidity Drawing under the Letter of Credit, the amount available under the Letter of Credit will be automatically reduced by the principal amount of the Bonds purchased with the proceeds of such drawing plus the amount of accrued interest on such Bonds. In the event of the remarketing of the Bonds purchased with the proceeds of a Liquidity Drawing, the amount available under the Letter of Credit will be automatically reinstated upon receipt by the Bank or the Trustee on the Bank's behalf of an amount equal to such principal amount plus accrued interest.

The Letter of Credit will terminate on the earliest to occur of:

(i) the Bank's close of business on December 1, 2011 (such date, as extended from time to time in accordance with the Letter of Credit is defined as the "Stated Expiration Date");

(ii) the Bank's close of business on the date which is five Business Days following the date of receipt by the Bank of a certificate from the Trustee certifying that (a) no Bonds remain Outstanding within the meaning of the Indenture, (b) all drawings required to be made under the Indenture and available under the Letter of Credit have

(iii) the Bank's close of business on the date of receipt by the Bank of a certificate from the Trustee confirming that the Trustee is required to terminate the Letter of Credit in accordance with the terms of the Indenture;

(iv) the date on which the Bank receives and honors an acceleration drawing certificate; or

(v) the Bank's close of business on the date which is 30 days after receipt by the Trustee of written notice from the Bank of an Event of Default under the $400,000,000 Revolving Credit Agreement dated as of November 1, 2010 among the Company, the lending institutions party thereto from time to time and Wells Fargo Bank, National Association, as Administrative Agent (the "Credit Agreement") and instructing the Trustee to draw under the Letter of Credit.

The Reimbursement Agreement

Pursuant to the Reimbursement Agreement, the Company is obligated to reimburse the Bank for all amounts drawn under the Letter of Credit, and to pay interest on all such amounts. The Company has also agreed to pay the Bank a periodic fee for issuing and maintaining the Letter of Credit.

The Reimbursement Agreement, through incorporation of the terms of the Credit Agreement, imposes various covenants and agreements, including various financial and operating covenants, on the Company. Such covenants include, but are not limited to, covenants relating to (i) inspection of the books and financial records of the Company; (ii) mergers or consolidations; and (iii) disposition of assets. Any such covenants may be amended, waived or modified at any time by the Bank and without the consent of the Trustee or the holders of the Bonds. Under certain circumstances, the failure of the Company to comply with such covenants may result in a mandatory tender or acceleration of the Bonds.

An Event of Default under the Credit Agreement will constitute an Event of Default under the Reimbursement Agreement. The following events will constitute an Event of Default under the Credit Agreement:

(i) the Borrower shall fail to pay when due any principal on any Loans under the Credit Agreement or Reimbursement Obligations; or

(ii) the Company shall fail to pay when due any interest on the Loans under the Credit Agreement and Reimbursement Obligations, any fee or any other amount payable hereunder or under any other Loan Document for five (5) days following the date such payment becomes due thereunder; or

(iii) the Company shall fail to observe or perform certain covenants or agreements contained in the Credit Agreement, including those related to mergers, disposition of assets and capitalization ratios; or

(iv) the Company shall fail to give notice of a Default or Event of Default under the Credit Agreement within a specified number of days following knowledge of such occurrence; or

(v) the Company shall fail to observe or perform any covenant or agreement contained in the Credit Agreement or any notes issued thereunder (other than those covered above) for thirty (30) days after written notice thereof has been given to the defaulting party by the administrative agent, or at the request of the required lenders; or

(vi) any representation, warranty or certification made by the Company in the Credit Agreement or any notes issued thereunder or in any certificate, financial statement or other document delivered pursuant hereto or thereto shall prove to have been incorrect in any material respect when made or deemed made; or

(vii) the Company shall (i) fail to pay any principal or interest, regardless of amount, due in respect of any Material Debt beyond any period of grace provided with respect thereto, or (ii) fail to observe or perform any other term, covenant, condition or agreement contained in any agreement or instrument evidencing or governing any such Material Debt beyond any period of grace provided with respect thereto if the effect of any failure referred to in this clause (ii) is to cause, or to permit the holder or holders of such Debt or a trustee on its or their behalf to cause, such Debt to become due prior to its stated maturity; or

(viii) the Company shall commence a voluntary case or other proceeding seeking liquidation, reorganization or other relief with respect to itself or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any substantial part of its property, or shall consent to any such relief or to the appointment of or taking possession by any such official in an involuntary case or other proceeding commenced against it, or shall make a general assignment for the benefit of creditors, or shall fail generally to pay, or shall admit in writing its inability to pay, its debts as they become due, or shall take any corporate action to authorize any of the foregoing; or

(ix) an involuntary case or other proceeding shall be commenced against the Company seeking liquidation, reorganization or other relief with respect to it or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any substantial part of its property, and such involuntary case or other proceeding shall remain undismissed and unstayed for a period of 60 days; or an order for relief shall be entered against the Company under the Bankruptcy Code; or

(x) any member of the ERISA Group shall fail to pay when due an amount or amounts aggregating in excess of $50,000,000 which it shall have become liable to pay under Title IV of ERISA; or notice of intent to terminate a Material Plan shall be filed under Title IV of

ERISA by any member of the ERISA Group, any plan administrator or any combination of the foregoing; or the PBGC shall institute proceedings under Title IV of ERISA to terminate, to impose liability (other than for premiums under Section 4007 of ERISA) in respect of, or to cause a trustee to be appointed to administer any Material Plan; or a condition shall exist by reason of which the PBGC would be entitled to obtain a decree adjudicating that any Material Plan must be terminated; or there shall occur a complete or partial withdrawal from, or default, within the meaning of Section 4219(c)(5) of ERISA, with respect to, one or more Multiemployer Plans which could reasonably be expected to cause one or more members of the ERISA Group to incur a current payment obligation in excess of $50,000,000; or

(xi) the Company shall fail within sixty (60) days to pay, bond or otherwise discharge any judgment or order for the payment of money in excess of $20,000,000, entered against the Company that is not stayed on appeal or otherwise being appropriately contested in good faith; or

(xii) a Change of Control shall have occurred;

For purposes of the foregoing:

"Change of Control" means (i) the acquisition by any person, or two or more persons acting in concert, of beneficial ownership of 25% or more of the outstanding shares of voting stock of PPL Corporation or its successors or (ii) the failure at any time of PPL Corporation or its successors to own 80% or more of the outstanding shares of the voting stock in the Company.

"Credit Agreement" means the $400,000,000 Revolving Credit Agreement dated as of November 1, 2010 among the Company, the lending institutions party thereto from time to time and Wells Fargo Bank, National Association, as Administrative Agent.

"Material Debt" means debt (other than the notes issued under the Credit Agreement) of the Company in a principal or face amount exceeding $50,000,000

Appendix C of the Reoffering Circular is hereby amended to read in its entirety as follows:

Wells Fargo Bank, National Association

The information under this heading has been provided solely by Wells Fargo Bank, National Association and is believed to be reliable. This information has not been verified independently by the Company, the Issuer or the Remarketing Agent. The Company, the Issuer and the Remarketing Agent make no representation whatsoever as to the accuracy, adequacy or completeness of such information.

Wells Fargo Bank, National Association

Wells Fargo Bank, National Association (the "Bank") is a national banking association organized under the laws of the United States of America with its main office at 101 North Phillips Avenue, Sioux Falls, South Dakota 57104, and engages in retail, commercial and corporate banking, real estate lending and trust and investment services. The Bank is an indirect, wholly owned subsidiary of Wells Fargo & Company, a diversified financial services company, a financial holding company and a bank holding company registered under the Bank Holding Company Act of 1956, as amended, with its principal executive offices located in San Francisco, California.

Each quarter, the Bank files with the FDIC financial reports entitled "Consolidated Reports of Condition and Income for Insured Commercial Banks with Domestic and Foreign Offices," commonly referred to as the "Call Reports." The Bank's Call Reports are prepared in accordance with regulatory accounting principles, which may differ from generally accepted accounting principles. The publicly available portions of Call Reports filed by the Bank with the FDIC may be obtained from the FDIC, Disclosure Group, Room F518, 550 17th Street, N.W., Washington, D.C. 20429 at prescribed rates, or from the FDIC on its Internet site at http://www.fdic.gov, or by writing to Corporate Secretary's Office, Wells Fargo Center, Sixth and Marquette, MAC N9305-173, Minneapolis, MN 55479.

The Letter of Credit will be solely an obligation of the Bank and will not be an obligation of, or otherwise guaranteed by, Wells Fargo & Company, and no assets of Wells Fargo & Company or any affiliate of the Bank or Wells Fargo & Company will be pledged to the payment thereof. Payment of the Letter of Credit will not be insured by the FDIC.

The information contained in this section, including financial information, relates to and has been obtained from the Bank, and is furnished solely to provide limited introductory information regarding the Bank and does not purport to be comprehensive. Any financial information provided in this section is qualified in its entirety by the detailed information appearing in the Call Reports referenced above. The delivery hereof shall not create any implication that there has been no change in the affairs of the Bank since the date hereof.

Appendix A of the Reoffering Circular is hereby amended to read in its entirety as follows:

Appendix A

[DELETED AND REPLACED – SEE APPENDIX A TO SUPPLEMENT DATED MAY 2, 2011]

Supplement, dated October 29, 2010 to Reoffering Circular dated December 10, 2008, as supplemented as of December 16, 2008 (the "Reoffering Circular")

$50,000,000
County of Carroll, Kentucky
Environmental Facilities Revenue Bonds, 2004 Series A
(Kentucky Utilities Company Project)

Effective as of October 29, 2010, the above-referenced bonds (the "Bonds") will be further secured by the delivery to U.S. Bank National Association, as trustee for the Bonds (the "Trustee"), of a tranche of first mortgage bonds of Kentucky Utilities Company (the "Company"). The principal amount, maturity date and interest rate (or method of determining interest rates) of such tranche of first mortgage bonds will be identical to the principal amount, maturity date and interest rate (or method of determining interest rates) of the Bonds. The first mortgage bonds will only be payable, and interest thereon will only accrue, as described herein. See "Security," "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds" and "Summary of the First Mortgage Bonds" for more information regarding the first mortgage bonds. The first mortgage bonds will not provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase in accordance with the Indenture (as hereinafter defined).

Please be advised that, as reflected in the Company's most recent financial statements that are filed on the Electronic Municipal Market Access (EMMA) system and are incorporated by reference herein, PPL Corporation has entered into an agreement with E.ON AG pursuant to which PPL Corporation would purchase all of the ownership interests of E.ON U.S. LLC, the Company's parent. Consummation of the transaction is subject to customary closing conditions, including receipt of all required regulatory approvals. Subject to receipt of such approvals, the transaction is expected to close by the end of 2010. If the transaction is completed, the Company will become an indirect wholly-owned subsidiary of PPL Corporation.

Except as otherwise specified herein, information in the Reoffering Circular referred to above has not been amended or modified and the information contained herein is qualified by reference to, and should be read in conjunction with, the Reoffering Circular, including information incorporated therein by reference. Terms not otherwise defined herein shall have the meanings ascribed to them in such Reoffering Circular.

The section of the Reoffering Circular captioned "Security; Limitation on Liens" is hereby amended to read in its entirety as follows:

Security

Payment of the principal of and interest and any premium on the Bonds will be secured by an assignment by the Issuer to the Trustee of the Issuer's interest in and to the Loan Agreement and all payments to be made pursuant thereto (other than certain indemnification and expense payments). Pursuant to the Loan Agreement, the Company will agree to pay, among other things, amounts sufficient to pay the aggregate principal amount of and premium, if any, on the Bonds, together with interest thereon as and when the same become due. The Company further will agree to make payments of the purchase price of the Bonds tendered for purchase to the extent that funds are not otherwise available therefor under the provisions of the Indenture.

The payment of the principal of and interest and any premium on the Bonds will be further secured by a separate tranche of the Company's First Mortgage Bonds, Collateral Series 2010 (the "First Mortgage Bonds") to be issued under an Indenture, dated as of October 1, 2010, as supplemented (the "First Mortgage Indenture"), between the Company and The Bank of New York Mellon, as trustee (the "First Mortgage Trustee"). The principal amount of the First Mortgage Bonds will equal the principal amount of the Bonds. If the Bonds become immediately due and payable as a result of a default in payment of the principal of, premium, if any, or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement and upon receipt by the First Mortgage Trustee of a written demand from the Trustee for redemption of the First Mortgage Bonds, or if all first mortgage bonds outstanding under the First Mortgage Indenture shall have been immediately due and payable, such First Mortgage Bonds will bear interest at the same interest rate or rates borne by the Bonds and the principal of such First Mortgage Bonds, together with interest accrued thereon from the last date or dates to which interest on the Bonds has been paid in full, will be payable in accordance with the Supplemental Indenture. See "Summary of the First Mortgage Bonds."

The First Mortgage Bonds are not intended to provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase in accordance with the Indenture. The First Mortgage Bonds are secured by a lien on certain property owned by the Company. In certain circumstances, the Company is permitted to reduce the aggregate principal amount of its First Mortgage Bonds held by the Trustee, but in no event to an amount lower than the aggregate outstanding principal amount of the Bonds.

* * * *

The section of the Reoffering Circular captioned "Summary of the Loan Agreement — Limitation on Liens" is hereby deleted. The sections of the Reoffering Circular captioned "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds"; " — Insurance"; " — Events of Default" and " — Remedies" are hereby added or amended, as applicable, to read in their entirety as follows:

Summary of the Loan Agreement

*　　*　　*　　*

Issuance and Delivery of First Mortgage Bonds

For the purpose of providing security for the Bonds, the Company will execute and deliver to the Trustee the First Mortgage Bonds. The principal amount of the First Mortgage Bonds executed and delivered to the Trustee will be equal to the aggregate principal amount of the Bonds. If the Bonds become immediately due and payable as a result of a default in payment of the principal of, premium, if any, or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement and upon receipt by the First Mortgage Trustee of a written demand from the Trustee for redemption of the First Mortgage Bonds, or if all first mortgage bonds outstanding under the First Mortgage Indenture shall have been immediately due and payable, such First Mortgage Bonds will bear interest at the same interest rate or rates borne by the Bonds and the principal of such First Mortgage Bonds, together with interest accrued thereon from the last date to which interest on the Bonds shall have been paid in full, will then be payable. See, however, "Summary of the Indenture — Waiver of Events of Default."

Upon payment of the principal of, premium, if any, and interest on any of the Bonds, and the surrender to and cancellation thereof by the Trustee, or upon provision for the payment thereof having been made in accordance with the Indenture, First Mortgage Bonds with corresponding principal amounts equal to the aggregate principal amount of the Bonds so surrendered and canceled or for the payment of which provision has been made, will be surrendered by the Trustee to the First Mortgage Trustee and will be canceled by the First Mortgage Trustee. The First Mortgage Bonds will be registered in the name of the Trustee and will be non transferable, except to effect transfers to any successor trustee under the Indenture.

Insurance

The Company has agreed to insure the Project in accordance with the provisions of the First Mortgage Indenture.

Events of Default

Each of the following events constitutes an "event of default" under the Loan Agreement:

(1) failure by the Company to pay the amounts required for payment of the principal of, including purchase price for tendered Bonds and redemption and acceleration prices, and interest accrued, on the Bonds, at the times specified therein taking into account any periods of grace provided in the Indenture and the Bonds for the

(2) failure by the Company to observe and perform any covenant, condition or agreement, other than as referred to in paragraph (1) above, for a period of thirty days after written notice by the Issuer or Trustee, provided, however, that if such failure is capable of being corrected, but cannot be corrected in such 30-day period, it will not constitute an event of default under the Loan Agreement if corrective action with respect thereto is instituted within such period and is being diligently pursued;

(3) certain events of bankruptcy, dissolution, liquidation, reorganization or insolvency of the Company;

(4) the occurrence of an event of default under the Indenture; or

(5) all first mortgage bonds outstanding under the First Mortgage Indenture, if not already due, shall have become immediately due and payable, whether by declaration or otherwise, and such acceleration shall not have been rescinded or annulled by the First Mortgage Trustee.

Under the Loan Agreement, certain of the Company's obligations (other than the Company's obligations, among others, (i) not to permit any action which would result in interest paid on the Bonds being included in gross income for federal and Kentucky income taxes; (ii) to maintain its corporate existence and good standing, and to neither dispose of all or substantially all of its assets or consolidate with or merge into another corporation unless certain provisions of the Loan Agreement are satisfied; and (iii) to make loan payments and certain other payments under the provisions of the Loan Agreement) may be suspended if by reason of force majeure (as defined in the Loan Agreement) the Company is unable to carry out such obligations.

Remedies

Upon the happening of an event of default under the Loan Agreement, the Trustee, on behalf of the Issuer, may, among other things, take whatever action at law or in equity may appear necessary or desirable to collect the amounts then due and thereafter to become due, or to enforce performance and observance of any obligation, agreement or covenant of the Company, under the Loan Agreement, including any remedies available in respect of the First Mortgage Bonds.

In the event of a default in payment of the principal of, premium, if any, or interest on the Bonds and the acceleration of the maturity date of the Bonds (to the extent not already due and payable) as a consequence of such event of default, the Trustee may demand redemption of the First Mortgage Bonds. See "Summary of the First Mortgage Bonds" and "Summary of the Indenture — Defaults and Remedies." Any amounts collected upon the happening of any such event of default will be applied in accordance with the Indenture or, if the Bonds have been fully paid (or provision for payment thereof has been made in accordance with the Indenture) and all other liabilities of the Company accrued under the Indenture and the Loan Agreement have been paid or satisfied, made available to the Company.

*   *   *   *

A new section is hereby added to the Reoffering Circular to read in its entirety as follows:

Summary of the First Mortgage Bonds

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the First Mortgage Bonds and the First Mortgage Indenture. This description is only a summary and does not purport to be complete and definitive. Reference is made to the First Mortgage Indenture and to the form of the First Mortgage Bonds for the detailed provisions thereof.

General

The First Mortgage Bonds, in a principal amount equal to the principal amount of the Bonds, were issued as a new tranche from a new series of first mortgage bonds under the First Mortgage Indenture (see "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds"). The statements herein made (being for the most part summaries of certain provisions of the First Mortgage Indenture) are subject to the detailed provisions of the First Mortgage Indenture, which is incorporated herein by this reference. Words or phrases italicized are defined in the First Mortgage Indenture.

The First Mortgage Bonds will mature on the same date and bear interest at the same rate or rates as the Bonds; however, the principal of and interest on the First Mortgage Bonds will not be payable other than upon the occurrence of an event of default under the Loan Agreement. If the Bonds become immediately due and payable as a result of a default in payment of the principal of, premium, if any, or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement, and if all first mortgage bonds outstanding under the First Mortgage Indenture shall not have become immediately due and payable following an event of default under the First Mortgage Indenture, the Company will be obligated to redeem the First Mortgage Bonds upon receipt by the First Mortgage Trustee of a Redemption Demand from the Trustee for redemption, at a redemption price equal to the principal amount thereof plus accrued interest at the rates borne by the Bonds from the last date to which interest on the Bonds has been paid.

The First Mortgage Bonds at all times will be in fully registered form registered in the name of the Trustee, will be non-negotiable, and will be non-transferable except to any successor trustee under the Indenture. Upon payment and cancellation of Bonds by the Trustee or the Paying Agent (other than any Bond or portion thereof that was canceled by the Trustee or the Paying Agent and for which one or more Bonds were delivered and authenticated pursuant to the Indenture), whether at maturity, by redemption or otherwise, or upon provision for the payment of the Bonds having been made in accordance with the Indenture, an equal principal amount of

First Mortgage Bonds will be deemed fully paid and the obligations of the Company thereunder will cease.

Security; Lien of the First Mortgage Indenture

General. Except as described below under this heading and under "— Issuance of Additional First Mortgage Bonds," and subject to the exceptions described under "— Satisfaction and Discharge," all first mortgage bonds issued under the First Mortgage Indenture, including the Bonds, will be secured, equally and ratably, by the lien of the First Mortgage Indenture, which constitutes, subject to permitted liens as described below, a first mortgage lien on substantially all of the Company's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity (other than property duly released from the lien of the First Mortgage Indenture in accordance with the provisions thereof and other than excepted property, as described below). Property that is subject to the lien of the First Mortgage Indenture is referred to herein as "Mortgaged Property."

The Company may obtain the release of property from the lien of the First Mortgage Indenture from time to time, upon the bases provided for such release in the First Mortgage Indenture. See "— Release of Property."

The Company may enter into supplemental indentures with the First Mortgage Trustee, without the consent of the holders of the first mortgage bonds, in order to subject additional property (including property that would otherwise be excepted from such lien) to the lien of the First Mortgage Indenture. This property would constitute *property additions* and would be available as a basis for the issuance of additional first mortgage bonds. See "— Issuance of Additional First Mortgage Bonds."

The First Mortgage Indenture provides that after-acquired property (other than *excepted property*) will be subject to the lien of the First Mortgage Indenture. However, in the case of consolidation or merger (whether or not the Company is the surviving company) or transfer of the Mortgaged Property as or substantially as an entirety, the First Mortgage Indenture will not be required to be a lien upon any of the properties either owned or subsequently acquired by the successor company except properties acquired from the Company in or as a result of such transfer, as well as improvements, extensions and additions (as defined in the First Mortgage Indenture) to such properties and renewals, replacements and substitutions of or for any part or parts thereof. See "— Consolidation, Merger and Conveyance of Assets as an Entirety."

Excepted Property. The lien of the First Mortgage Indenture does not cover, among other things, the following types of property: property located outside of Kentucky and not specifically subjected or required to be subjected to the lien of the First Mortgage Indenture; property not used by the Company in its electric generation, transmission and distribution business; cash and securities not paid, deposited or held under the First Mortgage Indenture; contracts, leases and other agreements of all kinds, contract rights, bills, notes and other instruments, revenues, accounts receivable, claims, demands and judgments; governmental and other licenses, permits, franchises, consents and allowances; intellectual property rights and other general intangibles; vehicles, movable equipment, aircraft and vessels; all goods, stock in trade, wares, merchandise and inventory held for the purpose of sale or lease in the ordinary course of business; materials, supplies, inventory and other personal property consumable in the operation of the Company's business; fuel; tools and equipment; furniture and furnishings; computers and data processing, telecommunications and other facilities used primarily for administrative or clerical purposes or otherwise not used in connection with the operation or maintenance of electric generation, transmission and distribution facilities; coal, ore, gas, oil and other minerals and timber rights; electric energy and capacity, gas, steam, water and other products generated, produced, manufactured, purchased or otherwise acquired; real property and facilities used primarily for the production or gathering of natural gas; property which has been released from the lien of the First Mortgage Indenture; and leasehold interests. Property of the Company not covered by the lien of the First Mortgage Indenture is referred to herein as excepted property. Properties held by any of the Company's subsidiaries, as well as properties leased from others, would not be subject to the lien of the First Mortgage Indenture.

Permitted Liens. The lien of the First Mortgage Indenture is subject to permitted liens described in the First Mortgage Indenture. Such *permitted liens* include liens existing at the execution date of the First Mortgage Indenture, purchase money liens and other liens placed or otherwise existing on property acquired by the Company after the execution date of the First Mortgage Indenture at the time the Company acquires it, tax liens and other governmental charges which are not delinquent or which are being contested in good faith, mechanics', construction and materialmen's liens, certain judgment liens, easements, reservations and rights of others (including governmental entities) in, and defects of title to, the Company's property, certain leases and leasehold interests, liens to secure public obligations, rights of others to take minerals, timber, electric energy or capacity, gas, water, steam or other products produced by the Company or by others on the Company's property, rights and interests of persons other than the Company arising out of agreements relating to the common ownership or joint use of property, and liens on the interests of such persons in such property and liens which have been bonded or for which other security arrangements have been made.

The First Mortgage Indenture also provides that the First Mortgage Trustee will have a lien, prior to the lien on behalf of the holders of the first mortgage bonds, including the First Mortgage Bonds, upon the Mortgaged Property as security for the Company's payment of its reasonable compensation and expenses and for indemnity against certain liabilities. Any such lien would be a *permitted lien* under the First Mortgage Indenture.

Issuance of Additional First Mortgage Bonds

The maximum principal amount of first mortgage bonds that may be authenticated and delivered under the First Mortgage Indenture is subject to the issuance restrictions described below; provided, however, that the maximum principal amount of first mortgage bonds outstanding at any one time shall not exceed One Quintillion Dollars ($1,000,000,000,000,000,000), which amount may be changed by supplemental indenture. First mortgage bonds of any series may be issued from time to time on the basis of, and in an aggregate principal amount not exceeding:

- 66 2/3% of the *cost* or *fair value* to the Company (whichever is less) of *property additions* (as described below) which do not constitute *funded property* (generally, *property additions* which have been made the basis of the authentication and delivery of first mortgage bonds, the release of Mortgaged Property or the withdrawal of cash, which have been substituted for retired *funded property* or which have been used for other specified purposes) after certain deductions and additions, primarily including adjustments to offset property retirements;

- the aggregate principal amount of *retired securities* (as described below); or

- an amount of cash deposited with the First Mortgage Trustee.

Property additions generally include any property which is owned by the Company and is subject to the lien of the First Mortgage Indenture except (with certain exceptions) goodwill, going concern value rights or intangible property, or any property the acquisition or construction of which is properly chargeable to one of the Company's operating expense accounts.

Retired securities means, generally, first mortgage bonds which are no longer outstanding under the First Mortgage Indenture, which have not been retired by the application of *funded cash* and which have not been used as the basis for the authentication and delivery of first mortgage bonds, the release of property or the withdrawal of cash.

The First Mortgage Bonds will be issued on the basis of *property additions*. At August 31, 2010, approximately $2.3 billion of *property additions* were available to be used as the basis for the authentication and delivery of first mortgage bonds.

Release of Property

Unless an *event of default* has occurred and is continuing, the Company may obtain the release from the lien of the First Mortgage Indenture of any Mortgaged Property, except for cash held by the First Mortgage Trustee, upon delivery to the First Mortgage Trustee of an amount in cash equal to the amount, if any, by which sixty-six and two-thirds percent (66-2/3%) of the cost of the property to be released (or, if less, the *fair value* to the Company of such property at the time it became *funded property*) exceeds the aggregate of:

- an amount equal to 66 2/3% of the aggregate principal amount of obligations secured by *purchase money liens* upon the property to be released and delivered to the First Mortgage Trustee;

- an amount equal to 66 2/3% of the *cost* or *fair value* to the Company (whichever is less) of certified *property additions* not constituting *funded property* after certain deductions and additions, primarily including adjustments to offset property retirements (except that such adjustments need not be made if such *property additions* were acquired or made within the 90-day period preceding the release);

- the aggregate principal amount of first mortgage bonds the Company would be entitled to issue on the basis of *retired securities* (with such entitlement being waived by operation of such release);

- the aggregate principal amount of first mortgage bonds delivered to the First Mortgage Trustee (with such first mortgage bonds to be canceled by the First Mortgage Trustee);

- any amount of cash and/or an amount equal to 66 2/3% of the aggregate principal amount of obligations secured by *purchase money liens* upon the property released delivered to the trustee or other holder of a lien prior to the lien of the First Mortgage Indenture, subject to certain limitations described in the First Mortgage Indenture; and

- any taxes and expenses incidental to any sale, exchange, dedication or other disposition of the property to be released.

As used in the First Mortgage Indenture, the term *purchase money* lien means, generally, a lien on the property being released which is retained by the transferor of such property or granted to one or more other persons in connection with the transfer or release thereof, or granted to or held by a trustee or agent for any such persons, and may include liens which cover property in addition to the property being released and/or which secure indebtedness in addition to indebtedness to the transferor of such property.

Unless an *event of default* has occurred and is continuing, property which is not *funded property* may generally be released from the lien of the First Mortgage Indenture without depositing any cash or property with the First Mortgage Trustee as long as (a) the aggregate amount of *cost* or *fair value* to the Company (whichever is less) of all *property additions* which do not constitute *funded property* (excluding the property to be released) after certain deductions and additions, primarily including adjustments to offset property retirements, is not less than zero or (b) the cost or *fair value* (whichever is less) of property to be released does not exceed the aggregate amount of the cost or fair value to the Company (whichever is less) of *property additions* acquired or made within the 90-day period preceding the release.

The First Mortgage Indenture provides simplified procedures for the release of minor properties and property taken by eminent domain, and provides for dispositions of certain obsolete property and grants or surrender of certain rights without any release or consent by the First Mortgage Trustee.

If the Company retains any interest in any property released from the lien of the First Mortgage Indenture, the First Mortgage Indenture will not become a lien on such property or such interest therein or any improvements, extensions or additions to such property or renewals, replacements or substitutions of or for such property or any part or parts thereof.

Withdrawal of Cash

Unless an *event of default* has occurred and is continuing, and subject to certain limitations, cash held by the First Mortgage Trustee may, generally, (1) be withdrawn by the Company (a) to the extent of sixty-six and two-thirds percent (66-2/3%) of the cost or *fair value* to the Company (whichever is less) of *property additions* not constituting *funded property*, after certain deductions and additions, primarily including adjustments to offset retirements (except that such adjustments need not be made if such *property additions* were acquired or made within the 90-day period preceding the withdrawal) or (b) in an amount equal to the aggregate principal amount of first mortgage bonds that the Company would be entitled to issue on the basis of *retired securities* (with the entitlement to such issuance being waived by operation of such withdrawal) or (c) in an amount equal to the aggregate principal amount of any outstanding first mortgage bonds delivered to the First Mortgage Trustee; or (2) upon the Company's request, be applied to (a) the purchase of first mortgage bonds in a manner and at a price approved by the Company or (b) the payment (or provision for payment) at stated maturity of any first mortgage bonds or the redemption (or provision for payment) of any first mortgage bonds which are redeemable; provided, however, that cash deposited with the First Mortgage Trustee as the basis for the authentication and delivery of first mortgage bonds may, in addition, be withdrawn in an amount not exceeding the aggregate principal amount of cash delivered to the First Mortgage Trustee for such purpose.

Events of Default

An "*event of default*" occurs under the First Mortgage Indenture if

- the Company does not pay any interest on any first mortgage bonds within 30 days of the due date;

- the Company does not pay principal or premium, if any, on any first mortgage bonds on the due date;

- the Company remains in breach of any other covenant (excluding covenants specifically dealt with elsewhere in this section) in respect of any first mortgage bonds for 90 days after the Company receives a written notice of default stating the Company is in breach and requiring remedy of the breach; the notice must be sent by either the First Mortgage Trustee or holders of 25% of the principal amount of outstanding first mortgage bonds; the First Mortgage Trustee or such holders can agree to extend the 90-day period and such an agreement to extend will be automatically deemed to occur if the Company initiates corrective action within such 90 day period and the Company is diligently pursuing such action to correct the default; or

- the Company files for bankruptcy or certain other events in bankruptcy, insolvency, receivership or reorganization occur.

Remedies

Acceleration of Maturity. If an event of default occurs and is continuing, then either the First Mortgage Trustee or the holders of not less than 25% in principal amount of the outstanding first mortgage bonds may declare the principal amount of all of the first mortgage bonds to be due and payable immediately.

Rescission of Acceleration. After the declaration of acceleration has been made and before the First Mortgage Trustee has obtained a judgment or decree for payment of the money due, such declaration and its consequences will be rescinded and annulled, if

- the Company pays or deposits with the First Mortgage Trustee a sum sufficient to pay:

- all overdue interest;
- the principal of and premium, if any, which have become due otherwise than by such declaration of acceleration and interest thereon;
- interest on overdue interest to the extent lawful;
- all amounts due to the First Mortgage Trustee under the First Mortgage Indenture; and

- all *events of default*, other than the nonpayment of the principal which has become due solely by such declaration of acceleration, have been cured or waived as provided in the First Mortgage Indenture.

For more information as to waiver of defaults, see "— Waiver of Default and of Compliance" below.

Appointment of Receiver and Other Remedies. Subject to the First Mortgage Indenture, under certain circumstances and to the extent permitted by law, if an *event of default* occurs and is continuing, the First Mortgage Trustee has the power to appoint a receiver of the Mortgaged Property, and is entitled to all other remedies available to mortgagees and secured parties under the Uniform Commercial Code or any other applicable law.

Control by Holders; Limitations. Subject to the First Mortgage Indenture, if an *event of default* occurs and is continuing, the holders of a majority in principal amount of the outstanding first mortgage bonds will have the right to

- direct the time, method and place of conducting any proceeding for any remedy available to the First Mortgage Trustee, or
- exercise any trust or power conferred on the First Mortgage Trustee.

The rights of holders to make direction are subject to the following limitations:

- the holders' directions may not conflict with any law or the First Mortgage Indenture; and
- the holders' directions may not involve the First Mortgage Trustee in personal liability where the First Mortgage Trustee believes indemnity is not adequate.

The First Mortgage Trustee may also take any other action it deems proper which is not inconsistent with the holders' direction.

In addition, the First Mortgage Indenture provides that no holder of any first mortgage bond will have any right to institute any proceeding, judicial or otherwise, with respect to the First Mortgage Indenture for the appointment of a receiver or for any other remedy thereunder unless

- that holder has previously given the First Mortgage Trustee written notice of a continuing *event of default*;

- the holders of 25% in aggregate principal amount of the outstanding first mortgage bonds have made written request to the First Mortgage Trustee to institute proceedings in respect of that *event of default* and have offered the First Mortgage Trustee reasonable indemnity against costs, expenses and liabilities incurred in complying with such request; and

- for 60 days after receipt of such notice, request and offer of indemnity, the First Mortgage Trustee has failed to institute any such proceeding and no direction inconsistent with such request has been given to the First Mortgage Trustee during such 60-day period by the holders of a majority in aggregate principal amount of outstanding first mortgage bonds.

Furthermore, no holder of any first mortgage bonds will be entitled to institute any such action if and to the extent that such action would disturb or prejudice the rights of other holders of first mortgage bonds.

However, each holder of any first mortgage bonds has an absolute and unconditional right to receive payment when due and to bring a suit to enforce that right.

Notice of Default. The First Mortgage Trustee is required to give the holders of the first mortgage bonds notice of any default under the First Mortgage Indenture to the extent required by the Trust Indenture Act, unless such default has been cured or waived; except that in the case of an *event of default* of the character specified in the third bullet point under "— Events of Default" (regarding a breach of certain covenants continuing for 90 days after the receipt of a written notice of default), no such notice shall be given to such holders until at least 60 days after the occurrence thereof. The Trust Indenture Act currently permits the First Mortgage Trustee to withhold notices of default (except for certain payment defaults) if the First Mortgage Trustee in good faith determines the withholding of such notice to be in the interests of the holders of the first mortgage bonds.

The Company will furnish the First Mortgage Trustee with an annual statement as to its compliance with the conditions and covenants in the First Mortgage Indenture.

Waiver of Default and of Compliance. The holders of a majority in aggregate principal amount of the outstanding first mortgage bonds may waive, on behalf of the holders of all outstanding first mortgage bonds, any past default under the First Mortgage Indenture, except a default in the payment of principal, premium or interest, or with respect to compliance with certain provisions of the First Mortgage Indenture that cannot be amended without the consent of the holder of each outstanding first mortgage bond affected.

Compliance with certain covenants in the First Mortgage Indenture or otherwise provided with respect to first mortgage bonds may be waived by the holders of a majority in aggregate principal amount of the affected first mortgage bonds, considered as one class.

Consolidation, Merger and Conveyance of Assets as an Entirety

Subject to the provisions described below, the Company has agreed to preserve its corporate existence.

The Company has agreed not to consolidate with or merge with or into any other entity or convey, transfer or lease the Mortgaged Property as or substantially as an entirety to any entity unless

- the entity formed by such consolidation or into which the Company merges, or the entity which acquires or which leases the Mortgaged Property substantially as an entirety, is an entity organized and existing under the laws of the United States of America or any State or Territory thereof or the District of Columbia, and

  - expressly assumes, by supplemental indenture, the due and punctual payment of the principal of, and premium and interest on, all the outstanding first mortgage bonds and the performance of all of the Company's covenants under the First Mortgage Indenture, and

  - such entity confirms the lien of the First Mortgage Indenture on the Mortgaged Property, including property thereafter acquired by such entity which constitutes an improvement, extension or addition to the Mortgaged Property or a renewal, replacement or substitution thereof;

- in the case of a lease, such lease is made expressly subject to termination by (i) the Company or by the First Mortgage Trustee and (ii) the purchaser of the property so leased at any sale thereof, at any time during the continuance of an *event of default*; and

- immediately after giving effect to such transaction, no *event of default*, and no event which after notice or lapse of time or both would become an *event of default*, will have occurred and be continuing.

In the case of the conveyance or other transfer of the Mortgaged Property as or substantially as an entirety to any other person, upon the satisfaction of all the conditions described above the Company would be released and discharged from all obligations under the First Mortgage Indenture and on the first mortgage bonds then outstanding unless the Company elects to waive such release and discharge.

The First Mortgage Indenture does not prevent or restrict:

- any consolidation or merger after the consummation of which the Company would be the surviving or resulting entity; or

- any conveyance or other transfer, or lease, of any part of the Mortgaged Property which does not constitute the entirety or substantially the entirety thereof.

If following a conveyance or other transfer, or lease, of any part of the Mortgaged Property, the fair value of the Mortgaged Property retained by the Company exceeds an amount equal to three-halves (3/2) of the aggregate principal amount of all outstanding first mortgage bonds, then the part of the Mortgaged Property so conveyed, transferred or leased shall be deemed not to constitute the entirety or substantially the entirety of the Mortgaged Property. This fair value will be determined within 90 days of the conveyance or transfer by an independent expert that the Company selects and that is approved by the First Mortgage Trustee.

Modification of First Mortgage Indenture

Without Holder Consent. Without the consent of any holders of first mortgage bonds, the Company and the First Mortgage Trustee may enter into one or more supplemental indentures for any of the following purposes:

- to evidence the succession of another entity to the Company;

- to add one or more covenants or other provisions for the benefit of the holders of all or any series or tranche of first mortgage bonds, or to surrender any right or power conferred upon the Company;

- to correct or amplify the description of any property at any time subject to the lien of the First Mortgage Indenture; or to better assure, convey and confirm unto the First Mortgage Trustee any property subject or required to be subjected to the lien of the First Mortgage Indenture; or to subject to the lien of the First Mortgage Indenture additional property (including property of others), to specify any additional Permitted Liens with respect to such additional property and to modify the provisions in the First Mortgage Indenture for dispositions of certain types of property without release in order to specify any additional items with respect to such additional property;

- to add any additional e*vents of default*, which may be stated to remain in effect only so long as the first mortgage bonds of any one more particular series remains outstanding;

- to change or eliminate any provision of the First Mortgage Indenture or to add any new provision to the First Mortgage Indenture that does not adversely affect the interests of the holders in any material respect;

- to establish the form or terms of any series or tranche of first mortgage bonds;

- to provide for the issuance of bearer securities;

- to evidence and provide for the acceptance of appointment of a successor First Mortgage Trustee or by a co-trustee or separate trustee;

- to provide for the procedures required to permit the utilization of a noncertificated system of registration for any series or tranche of first mortgage bonds;

- to change any place or places where

- the Company may pay principal, premium and interest,
- first mortgage bonds may be surrendered for transfer or exchange, and
- notices and demands to or upon the Company may be served;

- to amend and restate the First Mortgage Indenture as originally executed, and as amended from time to time, with such additions, deletions and other changes that do not adversely affect the interest of the holders in any material respect;
- to cure any ambiguity, defect or inconsistency or to make any other changes that do not adversely affect the interests of the holders in any material respect; or
- to increase or decrease the maximum principal amount of first mortgage bonds that may be outstanding at any time.

In addition, if the Trust Indenture Act is amended after the date of the First Mortgage Indenture so as to require changes to the First Mortgage Indenture or so as to permit changes to, or the elimination of, provisions which, at the date of the First Mortgage Indenture or at any time thereafter, were required by the Trust Indenture Act to be contained in the First Mortgage Indenture, the First Mortgage Indenture will be deemed to have been amended so as to conform to such amendment or to effect such changes or elimination, and the Company and the First Mortgage Trustee may, without the consent of any holders, enter into one or more supplemental indentures to effect or evidence such amendment.

With Holder Consent. Except as provided above, the consent of the holders of at least a majority in aggregate principal amount of the first mortgage bonds of all outstanding series, considered as one class, is generally required for the purpose of adding to, or changing or eliminating any of the provisions of, the First Mortgage Indenture pursuant to a supplemental indenture. However, if less than all of the series of outstanding first mortgage bonds are directly affected by a proposed supplemental indenture, then such proposal only requires the consent of the holders of a majority in aggregate principal amount of the outstanding first mortgage bonds of all directly affected series, considered as one class. Moreover, if the first mortgage bonds of any series have been issued in more than one tranche and if the proposed supplemental indenture directly affects the rights of the holders of first mortgage bonds of one or more, but less than all, of such tranches, then such proposal only requires the consent of the holders of a majority in aggregate principal amount of the outstanding first mortgage bonds of all directly affected tranches, considered as one class.

However, no amendment or modification may, without the consent of the holder of each outstanding first mortgage bond directly affected thereby,

- change the stated maturity of the principal or interest on any first mortgage bond (other than pursuant to the terms thereof), or reduce the principal amount, interest or premium payable (or method of calculating such rates)or change the currency in which any first mortgage bond is payable, or impair the right to bring suit to enforce any payment;

- create any lien (not otherwise permitted by the First Mortgage Indenture) ranking prior to the lien of the First Mortgage Indenture with respect to all or substantially all of the Mortgaged Property, or terminate the lien of the First Mortgage Indenture on all or substantially all of the Mortgaged Property (other than in accordance with the terms of the First Mortgage Indenture), or deprive any holder of the benefits of the security of the lien of the First Mortgage Indenture;

- reduce the percentages of holders whose consent is required for any supplemental indenture or waiver of compliance with any provision of the First Mortgage Indenture or of any default thereunder and its consequences, or reduce the requirements for quorum and voting under the First Mortgage Indenture; or

- modify certain of the provisions of the First Mortgage Indenture relating to supplemental indentures, waivers of certain covenants and waivers of past defaults with respect to first mortgage bonds.

A supplemental indenture which changes, modifies or eliminates any provision of the First Mortgage Indenture expressly included solely for the benefit of holders of first mortgage bonds of one or more particular series or tranches will be deemed not to affect the rights under the First Mortgage Indenture of the holders of first mortgage bonds of any other series or tranche.

Satisfaction and Discharge

Any first mortgage bonds or any portion thereof will be deemed to have been paid and no longer outstanding for purposes of the First Mortgage Indenture and, at the Company's election, the Company's entire indebtedness with respect to those securities will be satisfied and discharged, if there shall have been irrevocably deposited with the First Mortgage Trustee or any Paying Agent (other than the Company), in trust:

- money sufficient, or

- in the case of a deposit made prior to the maturity of such first mortgage bonds, non-redeemable *eligible obligations* (as defined in the First Mortgage Indenture) sufficient, or

- a combination of the items listed in the preceding two bullet points, which in total are sufficient,

to pay when due the principal of, and any premium, and interest due and to become due on such first mortgage bonds or portions of such first mortgage bonds on and prior to their maturity.

The Company's right to cause its entire indebtedness in respect of the first mortgage bonds of any series to be deemed to be satisfied and discharged as described above will be subject to the satisfaction of any conditions specified in the instrument creating such series.

The First Mortgage Indenture will be deemed satisfied and discharged when no first mortgage bonds remain outstanding and when the Company has paid all other sums payable by it under the First Mortgage Indenture.

All moneys the Company pays to the First Mortgage Trustee or any Paying Agent on First Mortgage Bonds that remain unclaimed at the end of two years after payments have become due may be paid to or upon the Company's order. Thereafter, the holder of such First Mortgage Bond may look only to the Company for payment.

Duties of the First Mortgage Trustee; Resignation and Removal of the First Mortgage Trustee; Deemed Resignation

The First Mortgage Trustee will have, and will be subject to, all the duties and responsibilities specified with respect to an indenture trustee under the Trust Indenture Act. Subject to these provisions, the First Mortgage Trustee will be under no obligation to exercise any of the powers vested in it by the First Mortgage Indenture at the request of any holder of first mortgage bonds, unless offered reasonable indemnity by such holder against the costs, expenses and liabilities which might be incurred thereby. The First Mortgage Trustee will not be required to expend or risk its own funds or otherwise incur financial liability in the performance of its duties if the First Mortgage Trustee reasonably believes that repayment or adequate indemnity is not reasonably assured to it.

The First Mortgage Trustee may resign at any time by giving written notice to the Company.

The First Mortgage Trustee may also be removed by act of the holders of a majority in principal amount of the then outstanding first mortgage bonds of any series.

No resignation or removal of the First Mortgage Trustee and no appointment of a successor trustee will become effective until the acceptance of appointment by a successor trustee in accordance with the requirements of the First Mortgage Indenture.

Under certain circumstances, the Company may appoint a successor trustee and if the successor accepts, the First Mortgage Trustee will be deemed to have resigned.

Evidence to be Furnished to the First Mortgage Trustee

Compliance with First Mortgage Indenture provisions is evidenced by written statements of the Company's officers or persons selected or paid by the Company. In certain cases, opinions of counsel and certifications of an engineer, accountant, appraiser or other expert (who in some cases must be independent) must be furnished. In addition, the First Mortgage Indenture requires the Company to give to the First Mortgage Trustee, not less than annually, a brief statement as to the Company's compliance with the conditions and covenants under the First Mortgage Indenture.

Miscellaneous Provisions

The First Mortgage Indenture provides that certain first mortgage bonds, including those for which payment or redemption money has been deposited or set aside in trust as described under "— Satisfaction and Discharge" above, will not be deemed to be "outstanding" in determining whether the holders of the requisite principal amount of the outstanding first mortgage bonds have given or taken any demand, direction, consent or other action under the First Mortgage Indenture as of any date, or are present at a meeting of holders for quorum purposes.

The Company will be entitled to set any day as a record date for the purpose of determining the holders of outstanding first mortgage bonds of any series entitled to give or take any demand, direction, consent or other action under the First Mortgage Indenture, in the manner and subject to the limitations provided in the First Mortgage Indenture. In certain circumstances, the First Mortgage Trustee also will be entitled to set a record date for action by holders. If such a record date is set for any action to be taken by holders of particular first mortgage bonds, such action may be taken only by persons who are holders of such first mortgage bonds on the record date.

Governing Law

The First Mortgage Indenture and the first mortgage bonds provide that they are to be governed by and construed in accordance with the laws of the State of New York except where the Trust Indenture Act is applicable or where otherwise required by law. The effectiveness of the lien of the First Mortgage Indenture, and the perfection and priority thereof, will be governed by Kentucky law.

* * * *

The sections of the Reoffering Circular captioned "Summary of the Indenture — Surrender of First Mortgage Bonds"; "— Defaults and Remedies"; "— Waiver of Events of Default"; and "— Voting of First Mortgage Bonds Held by Trustee" are hereby added or amended, as applicable, to read in their entirety as follows:

Summary of the Indenture

* * * *

Surrender of First Mortgage Bonds

Upon payment of any principal of, premium, if any, and interest on any of the Bonds which reduces the principal amount of Bonds outstanding, or upon provision for the payment thereof having been made in accordance with the Indenture, First Mortgage Bonds in a principal amount equal to the principal amount of the Bonds so paid, or for the payment of which such provision has been made, shall be surrendered by the Trustee to the First Mortgage Trustee. The First Mortgage Bonds so surrendered shall be deemed fully paid and the obligations of the Company thereunder terminated.

Defaults and Remedies

Each of the following events constitutes an "Event of Default" under the Indenture:

(1) failure to make payment of any installment of interest on any Bond within a period of one Business Day from the due date;

(2) failure to make punctual payment of the principal of, or premium, if any, on any Bond on the due date, whether at the stated maturity thereof, or upon proceedings for redemption, or upon the maturity thereof by declaration or if payment of the purchase price of any Bond required to be purchased pursuant to the Indenture is not made when such payment has become due and payable;

(3) failure of the Issuer to perform or observe any other of the covenants, agreements or conditions in the Indenture or in the Bonds which failure continues for a period of 30 days after written notice by the Trustee, provided, however, that if such failure is capable of being cured, but cannot be cured in such 30-day period, it will not constitute an event of default under the Indenture if corrective action in respect of such failure is instituted within such 30-day period and is being diligently pursued;

(4) the occurrence of an "event of default" under the Loan Agreement (see "Summary of the Loan Agreement — Events of Default");

(5) written notice from the Credit Facility Issuer to the Trustee of an event of default under the Reimbursement Agreement, by reason of which the Trustee has been directed to accelerate the Bonds;

(6) if a Credit Facility is then held by the Trustee, on or before the close of business on the tenth calendar day following the honoring of a drawing under such Credit Facility

to pay interest on the Bonds on an Interest Payment Date, written notice from the Credit Facility Issuer to the Trustee that the interest component of the Credit Facility will not be reinstated; or

(7) all first mortgage bonds outstanding under the First Mortgage Indenture, if not already due, shall have become due and payable, whether by declaration or otherwise, and such acceleration shall not have been rescinded by the First Mortgage Trustee.

Upon the occurrence of an Event of Default under clauses (1), (2), (5), (6) or (7) above, the Trustee must: (i) enforce each and every right granted to the Trustee as a holder of the First Mortgage Bonds (see "Summary of the First Mortgage Bonds"), (ii) declare the principal of all Bonds and interest accrued thereon to be immediately due and payable, (iii) declare all payments under the Loan Agreement to be immediately due and payable and enforce each and every other right granted to the Issuer under the Loan Agreement for the benefit of the Bondholders and (iv) if a Credit Facility securing the Bonds is in effect, make an immediate drawing under the Credit Facility in accordance with its terms and deposit the proceeds of such drawing in the Bond Fund pending application to the payment of principal of the Bonds, subject to the provisions of the Indenture reserving to the Credit Facility Issuer the right to direct default proceedings and providing for termination of default proceedings upon certain occurrences.

Interest on the Bonds will cease to accrue on the date of issuance of the declaration of acceleration of payment of principal and interest on the Bonds.

In exercising such rights, the Trustee shall take any action that, in the judgment of the Trustee, would best serve the interests of the registered owners. Upon the occurrence of an Event of Default under the Indenture, the Trustee may also proceed to pursue any available remedy by suit at law or in equity to enforce the payment of the principal of, premium, if any, and interest on the Bonds then outstanding.

If an Event of Default under the Indenture shall occur and be continuing and the maturity date of the Bonds has been accelerated (to the extent the Bonds are not already due and payable) as a consequence of such event of default, the Trustee may, and upon the written request of the registered owners holding not less than 25% in principal amount of all Bonds then outstanding and upon receipt of indemnity satisfactory to it shall, exercise such rights as it shall possess under the First Mortgage Indenture as a holder of the First Mortgage Bonds and shall also issue a Redemption Demand for such First Mortgage Bonds to the First Mortgage Trustee.

If the Trustee recovers any moneys following an Event of Default, unless the principal of the Bonds shall have been declared due and payable, all such moneys shall be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent, (ii) to the payment of all interest then due on the Bonds and (iii) to the payment of unpaid principal and premium, if any, of the Bonds. If the principal of the Bonds has become due or has been accelerated, such moneys shall be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and (ii) to the payment of principal of and interest then due and unpaid on the Bonds. In each case, however, Trustee and Paying Agent fees or costs will not be payable from moneys derived from Credit Facility drawings, any remarketing proceeds or moneys constituting certain Available Moneys under the Indenture.

No Bondholder may institute any suit or proceeding in equity or at law for the enforcement of the Indenture unless an Event of Default has occurred of which the Trustee has been notified or is deemed to have notice, and registered owners holding not less than 25% in aggregate principal amount of Bonds then outstanding shall have made written request to the Trustee to proceed to exercise the powers granted under the Indenture or to institute such action in their own name and the Trustee shall fail or refuse to exercise its powers within a reasonable time after receipt of indemnity satisfactory to it.

Any judgment against the Issuer pursuant to the exercise of rights under the Indenture shall be enforceable only against specific assigned payments, funds and accounts under the Indenture in the hands of the Trustee. No deficiency judgment shall be authorized against the general credit of the Issuer.

No default under paragraph (3) above shall constitute an Event of Default until actual notice is given to the Issuer and the Company by the Trustee or to the Issuer, the Company and the Trustee by the registered owners holding not less than 25% in aggregate principal amount of all Bonds outstanding and the Issuer and the Company shall have had thirty days after such notice to correct the default and failed to do so. If the default is such that it cannot be corrected within the applicable period but is capable of being cured, it will not constitute an Event of Default if corrective action is instituted within the applicable period.

Notwithstanding the foregoing, in addition to the rights of the Trustee and the Bondholders to direct proceedings as described above, if a Credit Facility is in effect, for so long as such Credit Facility is outstanding and the Credit Facility Issuer is not in default in its duties under the Indenture or the Credit Facility, the Credit Facility Issuer will have the absolute right to direct all proceedings on behalf of the Bondholders of the Bonds. Additionally, if the Event of Default which has occurred is an Event of Default under paragraphs (5) or (6) above, the Credit Facility Issuer, if any, will have no right to direct the Trustee or the Bondholders with respect to any matters, including remedies, and the holders of a majority in aggregate principal amount of the Bonds then outstanding, will have the right, at any time, by an instrument or instruments in writing executed and delivered to the Trustee, to direct the time, method and place of conducting all proceedings to be taken in connection with the enforcement of the terms and conditions of the Indenture, or for the appointment of a receiver or any other proceedings hereunder; provided, that such direction shall not be otherwise than in accordance with the provisions of law and of the Indenture.

If an Event of Default has occurred under the Indenture due to failure by the Credit Facility Issuer, if any, to honor a properly presented and conforming drawing by the Trustee under the Credit Facility then in effect in accordance with the terms thereof, all obligations of the Trustee to the Credit Facility Issuer and all rights of such Credit Facility Issuer under the Indenture will be suspended until the earlier of the cure of such failure or all of the Bonds have been paid in full.

Waiver of Events of Default

Except as provided below, the Trustee may in its discretion waive any Event of Default under the Indenture and shall do so upon the written request of the registered owners holding a majority in principal amount of all Bonds then outstanding. If, after the principal of all Bonds then outstanding shall have been declared to be due and payable and prior to any judgment or decree for the appointment of a receiver or for the payment of the moneys due shall have been entered, (i) the Company has caused to be deposited with the Trustee a sum sufficient to pay all matured installments of interest upon all Bonds and the principal of and premium, if any, on any and all Bonds which shall have become due otherwise than by reason of such declaration and the expenses of the Trustee in connection with such default (with interest thereon as provided in the Indenture) and (ii) all Events of Default under the Indenture (other than nonpayment of the principal of Bonds due by said declaration) shall have been remedied, then such Event of Default shall be deemed waived and such declaration and its consequences rescinded and annulled by the Trustee. Such waiver, rescission and annulment shall be binding upon all Bondholders. No such waiver, rescission and annulment shall extend to or affect any subsequent Event of Default or impair any right or remedy consequent thereon.

Upon any waiver or rescission as described above or any discontinuance or abandonment of proceedings under the Indenture, the Trustee shall immediately rescind in writing any Redemption Demand of First Mortgage Bonds previously given to the First Mortgage Trustee. The rescission under the First Mortgage Indenture of a declaration that all first mortgage bonds outstanding under the First Mortgage Indenture are immediately due and payable shall also constitute a waiver of an Event of Default described in paragraph (6) under the subcaption "—Defaults and Remedies" above and a waiver and rescission of its consequences, provided that no such waiver or rescission shall extend to or affect any subsequent or other default or impair any right consequent thereon.

The Trustee may not waive any default under clauses (5) or (6) above unless the Trustee has received in writing from the Credit Facility Issuer a written notice of full reinstatement of the full amount of the Credit Facility and a written rescission of the notice of the Event of Default.

Notwithstanding the foregoing, nothing in the Indenture shall affect the right of a registered owner to enforce the payment of principal of, premium, if any, and interest on the Bonds after the maturity thereof.

Voting of First Mortgage Bonds Held by Trustee

The Trustee, as holder of the First Mortgage Bonds, shall attend any meeting of holders of first mortgage bonds outstanding under the First Mortgage Indenture as to which it receives due notice. The Trustee shall vote the First Mortgage Bonds held by it, or shall consent with respect thereto, proportionally in the way in which the Trustee reasonably believes will be the vote or consent of all other holders of first mortgage bonds outstanding under the First Mortgage Indenture then eligible to vote or consent.

Notwithstanding the foregoing, the Trustee may not vote the First Mortgage Bonds in favor of, or give consent to, any action which, in the Trustee's opinion, would materially adversely affect the First Mortgage Bonds in a manner not generally shared by all other series of first mortgage bonds, except upon notification by the Trustee to the registered owners of all Bonds then outstanding of such proposal and consent thereto of the registered owners of at least 66 2/3% in aggregate principal amount of all Bonds then outstanding.

NOT A NEW ISSUE **BOOK-ENTRY-ONLY**

On October 20, 2004, the date on which the Bonds were originally issued, Bond Counsel delivered its opinion that stated that, subject to the conditions and exceptions set forth under the caption "Tax Treatment," under then current law, interest on the Bonds would be excludable from the gross income of the recipients thereof for federal income tax purposes, except that no opinion was expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" or a "related person" of the Project as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on the Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. Such interest may be subject to certain federal income taxes imposed on certain corporations, including imposition of the branch profits tax on a portion of such interest. Bond Counsel was further of the opinion that interest on the Bonds would be excludable from the gross income of the recipients thereof for Kentucky income tax purposes and that, under then current law, the principal of the Bonds would be exempt from ad valorem taxes in Kentucky. Such opinion has not been updated as of the date hereof and no continuing tax exemption opinions are expressed by Bond Counsel. However, in connection with the reoffering of the Bonds as described herein, Bond Counsel will deliver its opinion to the effect that the delivery of a letter of credit (a) is authorized or permitted by the Act and the Indenture and (b) will not adversely affect the validity of the Bonds or any exclusion of the interest thereon from the gross income of the owners of the Bonds for federal income tax purposes. See "Tax Treatment" herein.

$50,000,000
County of Carroll, Kentucky,
Environmental Facilities Revenue Bonds,
2004 Series A
(Kentucky Utilities Company Project)
Due: October 1, 2034

Reoffering Date: December 17, 2008

The County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2004 Series A (Kentucky Utilities Company Project) (the ''Bonds'') are special and limited obligations of the County of Carroll, Kentucky (the ''Issuer''), payable by the Issuer solely from and secured by payments to be received by the Issuer pursuant to a Loan Agreement with

KENTUCKY UTILITIES COMPANY

(the ''Company''), except as payable from proceeds of such Bonds or investment earnings thereon. The Bonds do not constitute general obligations of the Issuer or a charge against the general credit or taxing powers thereof or of the Commonwealth of Kentucky or any other political subdivision of Kentucky. The Bonds are not entitled to the benefits of any financial guaranty insurance policies.

The Bonds were originally issued on October 20, 2004 and currently bear interest at a Weekly Rate. Pursuant to the Indenture under which the Bonds were issued, the Company has elected to deliver a letter of credit to the Trustee and reoffer the Bonds. The Bonds are subject to mandatory purchase on the Reoffering Date and are being reoffered by this Reoffering Circular. Merrill Lynch, Pierce, Fenner & Smith Incorporated will serve as the Remarketing Agent for the Bonds.

From the Reoffering Date through December 16, 2009 (the Letter of Credit (as defined below) expiration date, subject to extension or earlier termination), payment of the principal of and interest on the Bonds when due will be paid with funds drawn under an irrevocable transferable direct pay letter of credit (the ''Letter of Credit'') issued by

COMMERZBANK AG, NEW YORK BRANCH

The Letter of Credit will permit the Trustee to draw with respect to the Bonds up to an amount sufficient to pay (i) the principal thereof (or that portion of the purchase price corresponding to principal) plus (ii) interest thereon (or that portion of the purchase price corresponding to interest) at an assumed rate of 14% per annum for at least 45 days.

From and after the Reoffering Date, the Bonds will continue to bear interest at a Weekly Rate, determined by the Remarketing Agent in accordance with the Indenture, payable on the first Business Day of each calendar month, commencing on January 2, 2009. The interest rate period, interest rate and Interest Rate Mode will be subject to change under certain conditions, as described in this Reoffering Circular. The Bonds are subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption following a determination of taxability prior to maturity, as described in this Reoffering Circular. The Bonds are subject to mandatory purchase on any date on which the Bonds are converted to a different Interest Rate Mode and upon the expiration of the Letter of Credit or any Alternate Credit Facility.

The Bonds are registered in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company (''DTC''), New York, New York. DTC will act as securities depository. Except as described in this Reoffering Circular, purchases of beneficial ownership interests in the Bonds will be made in book-entry-only form in denominations of $100,000 and multiples thereof. Purchasers will not receive certificates representing their beneficial interest in the Bonds. See the information contained under the caption ''Summary of the Bonds—Book-Entry-Only System'' in this Reoffering Circular. The principal of, premium, if any, and interest on the Bonds will be paid by U.S. Bank National Association, a national banking association, as successor Trustee, to Cede & Co., as long as Cede & Co. is the registered owner of the Bonds. Disbursement of such payments to the DTC Participants is the responsibility of DTC, and disbursement of such payments to the purchasers of beneficial ownership interests is the responsibility of DTC's Direct and Indirect Participants, as more fully described in this Reoffering Circular.

Price: 100%

The Bonds are reoffered subject to prior sale, withdrawal or modification of the offer without notice (provided, however, that any such notice of withdrawal must be given on the Business Day prior to the Reoffering Date) and to the approval of legality by Stoll Keenon Ogden PLLC, Louisville, Kentucky, as Bond Counsel, and upon satisfaction of certain conditions. Certain legal matters will be passed upon for the Company by its counsel, Jones Day, Chicago, Illinois, and John R. McCall, Esq., Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer of the Company, for the Issuer by its County Attorney, and for the Remarketing Agent by its counsel, Winston & Strawn LLP, Chicago, Illinois. It is expected that the Bonds will be available for redelivery to DTC in New York, New York on or about December 17, 2008.

Merrill Lynch & Co.

Dated: December 10, 2008

No dealer, broker, salesman or other person has been authorized by the Issuer, the Company or the Remarketing Agent to give any information or to make any representation with respect to the Bonds, other than those contained in this Reoffering Circular, and, if given or made, such other information or representation must not be relied upon as having been authorized by any of the foregoing. The Remarketing Agent has provided the following sentence for inclusion in this Reoffering Circular. The Remarketing Agent has reviewed the information in this Reoffering Circular in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Remarketing Agent does not guarantee the accuracy or completeness of such information. The information and expressions of opinion herein are subject to change without notice, and neither the delivery of this Reoffering Circular nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the parties referred to above since the date hereof. The information set forth herein with respect to the Issuer has been obtained from the Issuer, and all other information has been obtained from the Company and from other sources that are believed to be reliable, but it is not guaranteed as to accuracy or completeness by, and is not to be construed as a representation by, the Remarketing Agent.

In connection with the reoffering of the Bonds, the Remarketing Agent may over-allot or effect transactions which stabilize or maintain the market prices of the Bonds at levels above those that might otherwise prevail in the open market. Such stabilizing, if commenced, may be discontinued at any time.

IN MAKING AN INVESTMENT DECISION, INVESTORS MUST RELY ON THEIR OWN EXAMINATION OF THE TERMS OF THE REOFFERING, INCLUDING THE MERITS AND RISKS INVOLVED. THESE SECURITIES HAVE NOT BEEN RECOMMENDED BY ANY FEDERAL OR STATE SECURITIES COMMISSION OR REGULATORY AUTHORITY. FURTHERMORE, THE FOREGOING AUTHORITIES HAVE NOT CONFIRMED THE ACCURACY OR DETERMINED THE ADEQUACY OF THIS DOCUMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

Table of Contents

$50,000,000
County of Carroll, Kentucky
Environmental Facilities Revenue Bonds,
2004 Series A
(Kentucky Utilities Company Project)
Due: October 1, 2034

Introductory Statement

This Reoffering Circular, including the cover page and appendices, is provided to furnish information in connection with the reoffering by the County of Carroll, Kentucky (the "Issuer") of its Environmental Facilities Revenue Bonds, 2004 Series A (Kentucky Utilities Company Project), in the aggregate principal amount of $50,000,000 (the "Bonds") issued on October 20, 2004 pursuant to an Indenture of Trust dated as of October 1, 2004 (the "Indenture") between the Issuer and U.S. Bank National Association, a national banking association (the "Trustee"), as successor Trustee, Paying Agent and Bond Registrar, as the same will be amended and restated as of September 1, 2008.

Pursuant to a Loan Agreement by and between Kentucky Utilities Company (the "Company") and the Issuer, dated as of October 1, 2004 (the "Loan Agreement") (as the same has been amended and restated pursuant to an ordinance of the Issuer adopted October 28, 2008) as of September 1, 2008, proceeds from the sale of the Bonds, other than accrued interest, if any, paid by the initial purchasers thereof, were loaned by the Issuer to the Company. The Loan Agreement is a separate undertaking by and between the Company and the Issuer.

The Company will continue to repay the loan under the Loan Agreement by making payments to the Trustee in sufficient amounts to pay the principal of and interest and any premium on, and purchase price of, the Bonds. See "Summary of the Loan Agreement — General." Pursuant to the Indenture, the Issuer's rights under the Loan Agreement (other than with respect to certain indemnification and expense payments and notification rights) were assigned to the Trustee as security for the Bonds.

The proceeds of the Bonds were applied to pay and discharge $50,000,000 in outstanding principal amount of "County of Carroll, Kentucky, Collateralized Solid Waste Disposal Facilities Revenue Bonds (Kentucky Utilities Company Project), 1993 Series A," dated December 1, 1993 (the "1993 Bonds"), previously issued by the Issuer to finance certain solid waste disposal facilities (the "Project") owned by the Company.

The Company is an operating subsidiary of E.ON U.S. LLC (formerly known as LG&E Energy LLC) and E.ON AG (the "Parents"). See "Appendix A — Kentucky Utilities Company — Financial Statements and Additional Information." The Parents will have no obligation to make any payments due under the Loan Agreement or any other payments of principal, interest, premium or purchase price of the Bonds.

The Bonds are being reoffered at a Weekly Rate, but may be subsequently converted to bear interest at a Daily Rate, a Flexible Rate, a Semi-Annual Rate, an Annual Rate or a Dutch Auction Rate. **This Reoffering Circular pertains only to the Bonds during such period of time that they bear interest at the Weekly Rate.**

The Bonds are special and limited obligations of the Issuer, and the Issuer's obligation to pay the principal of and interest and any premium on, and purchase price of, the Bonds is limited solely to the revenues and other amounts received by the Trustee under the Indenture pursuant to the Loan Agreement and the Letter of Credit (as defined below). The Bonds will not constitute an indebtedness, general obligation or pledge of the faith and credit or taxing power of the Issuer, the Commonwealth of Kentucky or any political subdivision thereof. The Bonds are not entitled to the benefits of any financial guaranty insurance policies.

Concurrently with, and as a condition to, the reoffering of the Bonds, the Company will cause to be delivered an irrevocable transferable direct pay letter of credit (the "Letter of Credit"), issued by Commerzbank AG, New York Branch (the "Bank"), to provide for the timely payment of principal of and accrued interest (calculated for at least 45 days at the maximum rate of 14% per annum) on, and purchase price of, the Bonds. The Company will be required to reimburse the Bank for all amounts drawn by the Trustee under the Letter of Credit pursuant to the terms of a Reimbursement Agreement, to be dated as of December 17, 2008 (the "Reimbursement Agreement"), between the Company and the Bank. The Letter of Credit will expire on December 16, 2009, unless extended or earlier terminated.

Upon expiration of the Letter of Credit or any Alternate Credit Facility, the related Bonds will be subject to mandatory tender for purchase. See "Summary of the Bonds — Mandatory Purchases of Bonds — Mandatory Purchase upon Delivery, Cancellation, Substitution, Extension, Termination or Expiration of Any Credit Facility or Replacement with an Alternate Credit Facility." As used in this Reoffering Circular, "Bank" or "Credit Facility Issuer" refers to the Bank as the issuer of the Letter of Credit and any other issuer of any Alternate Credit Facility delivered in accordance with the Indenture; "Letter of Credit" or "Credit Facility" means the Letter of Credit delivered under the Indenture and, as applicable, any Alternate Credit Facility which may be subsequently delivered in accordance with the Indenture; and "Reimbursement Agreement" refers to the initial Reimbursement Agreement under which the Letter of Credit is provided and any subsequent agreement entered into between the Company and any other party in connection with the delivery of any Alternate Credit Facility.

Merrill Lynch, Pierce, Fenner & Smith Incorporated will be appointed under the Indenture to serve as Remarketing Agent for the Bonds. Any Remarketing Agent may resign or be removed and a successor Remarketing Agent may be appointed in accordance with the terms of the Indenture and the Remarketing Agreement for the Bonds between the Remarketing Agent and the Company.

Brief descriptions of the Company, the Issuer, the Bonds, the Loan Agreement, the Indenture, the Letter of Credit and the Reimbursement Agreement are included in this Reoffering Circular. Appendix A to this Reoffering Circular has been furnished by the Company. The Issuer and Bond Counsel assume no responsibility for the accuracy or completeness of such Appendix A or such information. Appendix B to this Reoffering Circular contains the opinion of

Bond Counsel delivered on the date on which the Bonds were initially issued, and the proposed form of opinion of Bond Counsel to be delivered in connection with the reoffering of the Bonds and the delivery of the Letter of Credit. Appendix C to this Reoffering Circular contains information about the Bank. The Issuer and Bond Counsel assume no responsibility for the accuracy or completeness of such Appendix C or such information. Such descriptions and information do not purport to be complete, comprehensive or definitive and are not to be construed as a representation or a guaranty of accuracy or completeness. All references herein to the documents are qualified in their entirety by reference to such documents, and references herein to the Bonds are qualified in their entirety by reference to the definitive form thereof included in the Indenture. Copies of the Loan Agreement, the Indenture, the Letter of Credit and the Reimbursement Agreement will be available for inspection at the principal corporate trust office of the Trustee. Certain information relating to The Depository Trust Company ("DTC") and the book-entry-only system has been furnished by DTC. All statements herein are qualified in their entirety by reference to each such document and, with respect to the enforceability of certain rights and remedies, to laws and principles of equity relating to or affecting generally the enforcement of creditors' rights.

The Project

The Project has been completed, placed in operation, and is the property of the Company. The Project consists of certain solid waste disposal facilities at the Company's Ghent Generating Station located in Carroll County.

The Issuer

The Issuer is a public body corporate and politic duly created and existing as a county and political subdivision under the Constitution and laws of the Commonwealth of Kentucky. The Issuer is authorized by Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (collectively, the "Act") to (a) reoffer the Bonds and (b) amend and restate and continue to perform its obligations under the Loan Agreement and the Indenture. The Issuer, through its legislative body, the Fiscal Court, has adopted one or more ordinances authorizing the issuance of the Bonds and the execution and delivery of the related documents.

THE BONDS ARE SPECIAL AND LIMITED OBLIGATIONS PAYABLE SOLELY AND ONLY FROM CERTAIN SOURCES, INCLUDING AMOUNTS TO BE RECEIVED BY THE TRUSTEE FROM THE LETTER OF CREDIT AND BY OR ON BEHALF OF THE ISSUER UNDER THE LOAN AGREEMENT. THE BONDS DO NOT CONSTITUTE AN INDEBTEDNESS, GENERAL OBLIGATION OR PLEDGE OF THE FAITH AND CREDIT OR TAXING POWER OF THE ISSUER, THE COMMONWEALTH OF KENTUCKY OR ANY POLITICAL SUBDIVISION THEREOF, AND DO NOT GIVE RISE TO A PECUNIARY LIABILITY OF THE ISSUER OR A CHARGE AGAINST ITS GENERAL CREDIT OR TAXING POWERS.

Summary of the Bonds

General

The Bonds will be issued in the aggregate principal amount set forth on the cover page of this Reoffering Circular and will mature on October 1, 2034. The Bonds are also subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption prior to maturity as described herein.

The Bonds currently bear interest at a Weekly Rate. From and after the Reoffering Date, the Bonds will bear interest at a Weekly Rate and will be payable on the first Business Day of each calendar month, commencing on January 2, 2009. The Bonds will continue to bear interest at the Weekly Rate until a Conversion to another Interest Rate Mode is specified by the Company or until the redemption or maturity of the Bonds. The permitted Interest Rate Modes for the Bonds are (i) the “Flexible Rate,” (ii) the “Daily Rate,” (iii) the “Weekly Rate,” (iv) the “Semi-Annual Rate,” (v) the “Annual Rate,” (vi) the “Long Term Rate” and (vii) the “Dutch Auction Rate.” Changes in the Interest Rate Mode will be effected, and notice of such changes will be given, as described below in “— Conversion of Interest Rate Modes and Changes of Long Term Rate Periods.”

During each Rate Period for an Interest Rate Mode (other than a Dutch Auction Rate), the interest rate or rates for the Bonds in that Interest Rate Mode, and Flexible Rate Periods for Bonds accruing interest at a Flexible Rate, will be determined by the Remarketing Agent in accordance with the Indenture; provided that the interest rate or rates borne by any Bonds may not exceed the lesser of (i) the maximum interest rate permitted by applicable law or (ii) 14% per annum.

Interest on the Bonds which bear interest at a Flexible Rate, Daily Rate or Weekly Rate will be computed on the basis of a year of 365 or 366 days, as appropriate, and paid for the actual number of days elapsed. Interest on the Bonds which bear interest at a Semi-Annual Rate, Annual Rate or Long Term Rate will be computed on the basis of a 360-day year of twelve 30-day months. Interest on the Bonds which bear interest at a Dutch Auction Rate will be computed on the basis of a 360-day year for the actual number of days elapsed. Interest payable on any Interest Payment Date will be payable to the registered owner of the Bond as of the Record Date for such payment; provided that in the case of Bonds bearing interest at the Flexible Rate, interest will be payable to the registered owner of such Bond on the Interest Payment Date therefor. The Record Date, in the case of interest accrued at a Daily Rate or Weekly Rate, will be the close of business on the Business Day immediately preceding each Interest Payment Date, in the case of interest accrued at a Dutch Auction Rate, will be the close of business on the second Business Day immediately preceding each Interest Payment Date, and in the case of interest accrued at a Semi-Annual Rate, Annual Rate or Long Term Rate, will be the close of business on the fifteenth day (whether or not a Business Day) of the month preceding each Interest Payment Date.

The Bonds initially will be issued solely in book-entry-only form through DTC (or its nominee, Cede & Co.). So long as the Bonds are held in the book-entry-only system, DTC or its nominee will be the registered owner or holder of the Bonds for all purposes of the Indenture, the

Bonds and this Reoffering Circular. See "— Book-Entry-Only System" below. Individual purchases of book-entry interests in the Bonds will be made in book-entry-only form in (i) denominations of $25,000 and integral multiples thereof, if bearing interest at the Dutch Auction Rate, (ii) denominations of $100,000 or any integral multiple thereof, if bearing interest at the Daily Rate or the Weekly Rate, (iii) denominations of $100,000 or any integral multiple of $5,000 in excess of $100,000, if bearing interest at Flexible Rates, or (iv) denominations of $5,000 and integral multiples thereof, if bearing interest at the Semi-Annual Rate, the Annual Rate or the Long Term Rate.

Except as otherwise described below for Bonds held in DTC's book-entry-only system, the principal or redemption price of the Bonds is payable at the designated corporate trust office in Nashville, Tennessee, of the Trustee, as paying agent (the "Paying Agent"). Except as otherwise described below for Bonds held in DTC's book-entry-only system, interest on the Bonds is payable by check mailed to the owner of record; provided that interest payable on each Bond will be payable in immediately available funds by wire transfer within the continental United States or by deposit into a bank account maintained with the Paying Agent (i) if the Interest Rate Mode is the Daily Rate, the Weekly Rate, the Dutch Auction Rate or the Flexible Rate, or (ii) at the written request of any owner of record holding at least $1,000,000 aggregate principal amount of the Bonds, if the Interest Rate Mode is the Semi-Annual Rate, Annual Rate or Long Term Rate, received by the Trustee, as bond registrar (the "Bond Registrar"), at least one Business Day prior to any Record Date. Except as otherwise described below for Bonds held in DTC's book-entry-only system, if the Interest Rate Mode is the Flexible Rate, interest payable on each Bond will be paid only upon presentation and surrender of such Bond.

Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the principal office of the Bond Registrar, accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond (i) during the fifteen days before any mailing of a notice of redemption of Bonds, (ii) after such Bond has been called for redemption or (iii) for which a registered owner has submitted a demand for purchase (see "— Purchases of Bonds on Demand of Owner" below), or which has been purchased (see "— Payment of Purchase Price" below). Registration of transfers and exchanges will be made without charge to the registered owners of Bonds, except that the Bond Registrar may require any registered owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

The Bonds Are Not Insured

Upon the issuance of the Letter of Credit on the Reoffering Date, the Municipal Bond New Issue Insurance Policy (the "Bond Insurance Policy") issued by Financial Guaranty Insurance Company ("Financial Guaranty") on October 20, 2004 will have been irrevocably surrendered and cancelled. The Bonds described in this Reoffering Circular are not insured, and holders thereof will have no recourse to, under or against any bond insurance policy or bond insurer, including the aforementioned Bond Insurance Policy issued by Financial Guaranty.

Tender Agent

Owners may tender their Bonds, and in certain circumstances will be required to tender their Bonds, to the Tender Agent for purchase at the times and in the manner described below under "—Summary of Certain Provisions of the Bonds," "— Purchases of Bonds on Demand of Owner" and "— Mandatory Purchases of Bonds." So long as the Bonds are held in DTC's book-entry-only system, the Trustee will act as Tender Agent under the Indenture. Any successor Tender Agent appointed pursuant to the Indenture will also be a Paying Agent.

Remarketing Agent

Merrill Lynch, Pierce, Fenner & Smith Incorporated will act as the Remarketing Agent with respect to the Bonds (the "Remarketing Agent"). The Remarketing Agent may resign or be removed and a successor Remarketing Agent may be appointed in accordance with the terms of the Indenture and the Remarketing Agreement for the Bonds between the Remarketing Agent and the Company.

Special Considerations Relating to the Remarketing Agent

The Remarketing Agent is paid by the Company.

The Remarketing Agent's responsibilities include determining the interest rate from time to time and remarketing Bonds that are optionally or mandatorily tendered by the owners thereof (subject, in each case, to the terms of the Remarketing Agreement), all as further described herein. The Remarketing Agent is appointed by the Issuer at the request of the Company and paid by the Company for its services. As a result, the interests of the Remarketing Agent may differ from those of existing holders and potential purchasers of Bonds.

The Remarketing Agent routinely purchases bonds for its own account.

The Remarketing Agent acts as remarketing agent for a variety of variable rate demand obligations and, in its sole discretion, routinely purchases such obligations for its own account in order to achieve a successful remarketing of the obligations (i.e., because there are otherwise not enough buyers to purchase the obligations) or for other reasons. The Remarketing Agent is permitted, but not obligated, to purchase tendered Bonds for its own account and, if it does so, it may cease doing so at any time without notice. The Remarketing Agent may also make a market in the Bonds by routinely purchasing and selling Bonds other than in connection with an optional or mandatory tender and remarketing. Such purchases and sales may be at or below par. However, the Remarketing Agent is not required to make a market in the Bonds. The Remarketing Agent may also sell any Bonds it has purchased to one or more affiliated investment vehicles for collective ownership or enter into derivative arrangements with affiliates or others in order to reduce its exposure to the Bonds. The purchase of Bonds by the Remarketing Agent may create the appearance that there is greater third party demand for the Bonds in the market than is actually the case. The practices described above also may result in fewer Bonds being tendered in a remarketing.

Bonds may be offered at different prices on any date.

As more fully described under the caption "— Determination of Interest Rates for Interest Rate Modes," the Remarketing Agent shall determine the minimum rate of interest per annum which in the opinion of the Remarketing Agent, would be necessary on and as of such day to remarket the Bonds in a secondary market transaction at a price equal to the principal amount thereof plus accrued interest thereon, if any, provided that such rate of interest shall not exceed 14% per annum. The interest rate will reflect, among other factors, the level of market demand for the Bonds (including whether the Remarketing Agent is willing to purchase Bonds for its own account). There may or may not be Bonds tendered and remarketed on a day that the rate on the Bonds are set, the Remarketing Agent may or may not be able to remarket any Bonds tendered for purchase on such date at par and the Remarketing Agent may sell Bonds at varying prices to different investors on such date or any other date. The Remarketing Agent is not obligated to advise purchasers in a remarketing if it does not have third party buyers for all of the Bonds at the remarketing price. In the event the Remarketing Agent owns any Bonds for its own account, it may, in its sole discretion in a secondary market transaction outside the tender process, offer such Bonds on any date, including the day that the rate on the Bonds are set, at a discount to par to some investors.

The ability to sell the Bonds other than through the tender process may be limited.

The Remarketing Agent may buy and sell Bonds other than through the tender process. However, it is not obligated to do so and may cease doing so at any time without notice and may require holders that wish to tender their Bonds to do so through the Trustee with appropriate notice. Thus, investors who purchase the Bonds, whether in a remarketing or otherwise, should not assume that they will be able to sell their Bonds other than by tendering the Bonds in accordance with the tender process.

Certain Definitions

As used herein, each of the following terms will have the meaning indicated. Certain capitalized terms used herein and not otherwise defined will have the meanings set forth in the Indenture.

"*Alternate Credit Facility*" means an irrevocable letter of credit, a municipal bond insurance policy, a surety bond, a line or lines of credit, a guarantee or other similar agreement or agreements or any other agreement or agreements used to provide liquidity or credit support for the Bonds, satisfactory to the Company and the Remarketing Agent and containing administrative provisions reasonably satisfactory to the Trustee, issued and delivered to the Trustee in accordance with the Indenture.

"*Annual Rate Period*" means the period beginning on, and including, the Conversion Date to the Annual Rate and ending on, and including, the day next preceding the second Interest Payment Date thereafter, and each successive twelve-month period (or portion thereof) thereafter until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Beneficial Owner*" means the person in whose name a Bond is recorded as such upon the systems of DTC and each DTC Participant (as defined herein) or the registered holder of such Bond if such Bond is not then registered in the name of Cede & Co.

"*Business Day*" means any day other than a Saturday or Sunday or legal holiday or a day on which banking institutions located in the City of New York, New York, or the New York Stock Exchange or banking institutions in the city in which the principal office of the Trustee, the Bond Registrar, the Tender Agent, the Paying Agent, the Auction Agent, the Company, the Credit Facility Issuer or the Remarketing Agent is located are authorized by law or executive order to close.

"*Conversion*" means any conversion from time to time in accordance with the terms of the Indenture of the Bonds from one Interest Rate Mode to another Interest Rate Mode.

"*Conversion Date*" means the date on which any Conversion becomes effective.

"*Credit Facility*" means an irrevocable direct pay letter of credit or other credit enhancement or liquidity support facility, or any combination thereof, delivered to and in favor of the Trustee for the benefit of the owners of the Bonds pursuant to the Indenture and designated as a "Credit Facility" under the Indenture, and includes the Initial Credit Facility or any Alternate Credit Facility delivered to the Trustee pursuant to the Indenture.

"*Credit Facility Issuer*" means the Initial Credit Facility Issuer and the issuer of any Credit Facility or Alternate Credit Facility subsequently in effect.

"*Daily Rate Period*" means the period beginning on, and including, the Conversion Date to the Daily Rate and ending on and including the day preceding the next Business Day and each period thereafter beginning on and including a Business Day and ending on and including the day preceding the next succeeding Business Day until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Dutch Auction Rate*" means the rate of interest to be borne by the Bonds during each Dutch Auction Rate Period determined in accordance with the Indenture.

"*Dutch Auction Rate Period*" means the period during which the Bonds bear interest at the Dutch Auction Rate.

"*Flexible Rate*" means the Interest Rate Mode for the Bonds in which the interest rate for each Bond is determined with respect to that Bond during each Flexible Rate Period applicable to that Bond, as provided in the Indenture.

"*Flexible Rate Period*" means with respect to any Bond, each period (which may be from one day to 364 days, or such lower maximum number of days as is then permitted under the Indenture) determined for such Bond, as provided in the Indenture.

"*Initial Credit Facility*" means the irrevocable direct pay letter of credit issued by the Initial Credit Facility Issuer to the Trustee with respect to the Bonds on the Reoffering Date.

"*Initial Credit Facility Issuer*" means Commerzbank AG, New York Branch.

"*Interest Payment Date*" means (i) if the Interest Rate Mode is the Daily Rate or the Weekly Rate, the first Business Day of each calendar month, (ii) if the Interest Rate Mode is the Flexible Rate, for each Bond the last day of each Flexible Rate Period for such Bond (or if such day is not a Business Day, the next succeeding Business Day), (iii) if the Interest Rate Mode is the Semi-Annual Rate, the Annual Rate or the Long Term Rate, April 1 and October 1, and, in the case of the Long Term Rate, the effective date of a change to a new Long Term Rate Period; (iv) if the Interest Rate Mode is the Dutch Auction Rate Mode, the dates determined in accordance with the terms of the Indenture; and (iv) any Conversion Date (including the date of a failed Conversion) or a change to a new Long Term Rate Period for such Bonds. In any case, the final Interest Payment Date will be the maturity date of the Bonds.

"*Interest Period*" means for all Bonds (or for any Bond if the Interest Rate Mode is the Flexible Rate) the period from and including each Interest Payment Date to and including the day immediately preceding the next Interest Payment Date, provided, however that the first Interest Period for the Bonds will begin on (and include) the date of issuance of the Bonds and the final Interest Period will end on September 30, 2034.

"*Interest Rate Mode*" means the Dutch Auction Rate, the Flexible Rate, the Daily Rate, the Weekly Rate, the Semi-Annual Rate, the Annual Rate and the Long Term Rate.

"*Long Term Rate Period*" means any period established by the Company as hereinafter set forth under "— Determination of Interest Rates for Interest Rate Modes — Long Term Rates and Long Term Rate Periods" and beginning on, and including, the Conversion Date to the Long Term Rate and ending on, and including, the day preceding the last Interest Payment Date for such period and, thereafter, each successive period of the same duration as the Long Term Rate Period previously established until the day preceding the earliest of the change to a different Long Term Rate Period, the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Prevailing Market Conditions*" means, without limitation, the following factors: existing short-term or long-term market rates for securities, the interest on which is excluded from gross income for federal income tax purposes; indexes of such short-term or long-term rates and the existing market supply and demand for securities bearing such short-term or long-term rates; existing yield curves for short-term or long-term securities for obligations of credit quality comparable to the Bonds, the interest on which is excluded from gross income for federal income tax purposes; general economic conditions; industry economic and financial conditions that may affect or be relevant to the Bonds; and such other facts, circumstances and conditions as the Remarketing Agent, in its sole discretion, determines to be relevant.

"*Purchase Date*" means any date on which Bonds are to be purchased on the demand of the registered owners thereof or are subject to mandatory purchase as described in the Indenture.

"*Reimbursement Agreement*" means the Reimbursement Agreement, to be dated as of December 17, 2008, between the Company and the Initial Credit Facility Issuer, as the same may be amended from time to time, and any other agreement between the Company and a Credit

Facility Issuer, setting forth the obligations of the Company to such Credit Facility Issuer arising out of any payments under such Credit Facility and which provides that it will be deemed to be a Reimbursement Agreement for the purpose of the Indenture.

"*Semi-Annual Rate Period*" means the period beginning on, and including, the Conversion Date to the Semi-Annual Rate, and ending on, and including, the day preceding the first Interest Payment Date thereafter and each successive six-month period thereafter beginning on and including an Interest Payment Date and ending on and including the day next preceding the next Interest Payment Date until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Weekly Rate Period*" means the period beginning on, and including, the Conversion Date to the Weekly Rate, and ending on, and including, the next Tuesday, and thereafter the period beginning on, and including, each Wednesday and ending on, and including, the earliest of the next Tuesday, the day preceding the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

Summary of Certain Provisions of the Bonds

The following table summarizes, for each of the permitted Interest Rate Modes (except the Dutch Auction Rate): the dates on which interest will be paid (*Interest Payment Dates*); the dates on which each interest rate will be determined (*Interest Rate Determination Dates*); the period of time (*Interest Rate Periods*) each interest rate will be in effect (provided that the initial Interest Rate Period for each Interest Rate Mode may begin on a different date from that specified, which date will be the Conversion Date or the date of a change in the Long Term Rate, as applicable); the dates on which registered owners may tender their Bonds for purchase to the Tender Agent and the notice requirements therefor (provided that while the Bonds are held in book-entry-only form, all notices of tender for purchase will be given by Beneficial Owners in the manner described under "— Purchases of Bonds on Demand of Owner — Notice Required for Purchases") (*Purchase on Demand of Owner; Required Notice*); the dates on which the Bonds are subject to mandatory tender for purchase (*Mandatory Purchase Dates*); the redemption provisions applicable to the Bonds (*Redemption*); the notice requirements for redemption and mandatory tender for purchase (*Notices of Redemption and Mandatory Purchases*); and the manner by which registered owners will receive payments of principal, interest, redemption price and purchase price (*Manner of Payment*). All times stated are New York City time.

	FLEXIBLE RATE	DAILY RATE	WEEKLY RATE
Interest Payment Dates	With respect to any Bond, the last day of each Flexible Rate Period (or if such day is not a Business Day, the next succeeding Business Day).	The first Business Day of each calendar month.	The first Business Day of each calendar month.
Interest Rate Determination Dates	For each Bond, not later than 12:00 noon on the first day of each Flexible Rate Period for such Bond.	Not later than 9:30 a.m. on each Business Day.	Not later than 4:00 p.m. on the day preceding each Weekly Rate Period or, if not a Business Day, on the next preceding Business Day.
Interest Rate Periods	For each Bond, each Flexible Rate Period will be of a duration designated by the Remarketing Agent of one day to 364 days (or lower maximum number as specified in the Indenture); must end on a day immediately prior to a Business Day.	From and including each Business Day to but not including the next Business Day.	From and including each Wednesday to and including the following Tuesday.
Purchase on Demand of Owner; Required Notice*	No purchase on demand of the owner.	Any Business Day; by written or telephonic notice, promptly confirmed in writing, to the Tender Agent by 10:00 a.m. on such Business Day.	Any Business Day; by written notice to the Tender Agent not later than 5:00 p.m. on a Business Day at least seven days prior to the Purchase Date.
Mandatory Purchase Dates	Any Conversion Date; with respect to each Bond, on each Interest Payment Date for such Bond; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.
Redemption	Optional at par on any Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day (other than extraordinary optional redemption as a result of damage, destruction or condemnation which will be on an Interest Payment Date).	Optional, Extraordinary Optional and Mandatory at par on any Business Day.	Optional, Extraordinary Optional and Mandatory at par on any Business Day.
Notices of Conversion, Redemption and Mandatory Purchases*	Not fewer than 15 days (30 days notice of Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days. No notice of mandatory purchase following end of each Flexible Rate Period.	Not fewer than 15 days (30 days notice of Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days.	Not fewer than 15 days (30 days notice of Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days.
Manner of Payment*	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.

* So long as DTC or its nominee is the registered owner of the Bonds, notices of redemption and mandatory purchases shall be sent to Cede & Co., payments of principal, redemption and purchase price of and interest on the Bonds will be paid through the facilities of DTC and notices of mandatory purchases may be given not less than five days prior to the Purchase Date. See "— Book-Entry-Only System" below.

	SEMI-ANNUAL	ANNUAL	LONG TERM
Interest Payment Date	Each April 1 and October 1.	Each April 1 and October 1.	Each April 1 and October 1; any Conversion Date; and the effective date of any change to a new Long Term Rate Period.
Interest Rate Determination Dates	Not later than 2:00 p.m. on the Business Day preceding the first day of the Semi-Annual Rate Period.	Not later than 12:00 noon on the Business Day preceding the first day of the Annual Rate Period.	Not later than 12:00 noon on the Business Day preceding the first day of the Long Term Rate Period.
Interest Rate Periods	Each six-month period from and including each April 1 and October 1 to and including the day preceding the next Interest Payment Date.	Each period from and including the Conversion Date to the Annual Rate to and including the day immediately preceding the second Interest Payment Date thereafter and each successive twelve month period thereafter.	Each period designated by the Company of more than one year in duration and which is an integral multiple of six months, from and including the first day of such period (April 1 and October 1) to and including the day immediately preceding the last Interest Payment Date for that period.
Purchase on Demand of Owner; Required Notice*	On any Interest Payment Date; by written notice to the Tender Agent on any Business Day not later than the fifteenth day prior to the Purchase Date.	On the final Interest Payment Date for the Annual Rate Period; by written notice to the Tender Agent on any Business Day not later than the fifteenth day prior to the Purchase Date.	On the final Interest Payment Date for the Long Term Rate Period; by written notice to the Tender Agent on a Business Day not later than the fifteenth day prior to the Purchase Date.
Mandatory Purchase Dates	Any Conversion Date; the first Business Day after the end of each Semi-Annual Rate Period; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; the first Business Day after the end of each Annual Rate Period; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; the first Business Day after the end of each Long Term Rate Period; the effective date of a change of Long Term Rate Period; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.
Redemption	Optional at par on any Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day (other than extraordinary optional redemption as a result of damage, destruction or condemnation which will be on an Interest Payment Date).	Optional at par on the final Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day.	Optional at times and prices dependent on the length of the Long Term Rate Period; Extraordinary Optional and Mandatory at par, on any Business Day.
Notices of Conversion, Redemption and Mandatory Purchases*	Not fewer than 15 days (30 days for notice of Conversion or redemption) or greater than 45 days.	Not fewer than 15 days (30 days for notice of Conversion or redemption) or greater than 45 days.	Not fewer than 15 days (30 days for notice of Conversion or redemption) or greater than 45 days.
Manner of Payment*	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner, of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner, of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner, of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.

* So long as DTC or its nominee is the registered owner of the Bonds, notices of redemption and mandatory purchases shall be sent to Cede & Co., payments of principal, redemption and purchase price of and interest on the Bonds will be paid through the facilities of DTC and notices of mandatory purchase may be given not less than five days prior to the Purchase Date. See "— Book-Entry-Only System" below.

Determination of Interest Rates for Interest Rate Modes

Daily Rate. If the Interest Rate Mode for the Bonds is the Daily Rate, the interest rate on the Bonds for any Business Day will be the rate established by the Remarketing Agent no later than 9:30 a.m. (New York City time) on such Business Day as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such Business Day at a price equal to the principal amount thereof, plus accrued interest, if any, thereon. For any day which is not a Business Day or if the Remarketing Agent does not give notice of a change in the interest rate, the interest rate on the Bonds will be the interest rate in effect for the immediately preceding Business Day.

Weekly Rate. If the Interest Rate Mode for the Bonds is the Weekly Rate, the interest rate on the Bonds for a particular Weekly Rate Period will be the rate established by the Remarketing Agent no later than 4:00 p.m. (New York City time) on the day preceding such Weekly Rate Period or, if such day is not a Business Day, on the next preceding Business Day, as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof, plus accrued interest, if any, thereon.

Flexible Rates and Flexible Rate Periods. If the Interest Rate Mode for the Bonds is the Flexible Rate, the interest rate on a Bond for a specific Flexible Rate Period will be the rate established by the Remarketing Agent no later than 12:00 noon (New York City time) on the first day of that Flexible Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell such Bond on that day at a price equal to the principal amount thereof. Each Flexible Rate Period applicable for a Bond will be determined separately by the Remarketing Agent on or prior to the first day of such Flexible Rate Period as being the Flexible Rate Period permitted under the Indenture which, in the judgment of the Remarketing Agent, taking into account then Prevailing Market Conditions, will, with respect to such Bond, ultimately produce the lowest overall interest cost on the Bonds while the Interest Rate Mode for the Bonds is the Flexible Rate. Each Flexible Rate Period will be from one day to 364 days in length and will end on a day preceding a Business Day. If the Remarketing Agent fails to set the length of a Flexible Rate Period for any Bond, a new Flexible Rate Period lasting to, but not including, the next Business Day (or until the earlier Conversion or maturity of the Bonds) will be established automatically in accordance with the Indenture.

Semi-Annual Rate. If the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the interest rate on the Bonds for a particular Semi-Annual Rate Period will be the rate established by the Remarketing Agent no later than 2:00 p.m. (New York City time) on the Business Day immediately preceding the first day of such Semi-Annual Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof.

Annual Rate. If the Interest Rate Mode for the Bonds is the Annual Rate, the interest rate on the Bonds for a particular Annual Rate Period will be the rate of interest established by the Remarketing Agent no later than 12:00 noon (New York City time) on the Business Day preceding the first day of such Annual Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof.

Dutch Auction Rate. If the Interest Rate Mode for the Bonds is the Dutch Auction Rate, the interest rate on the Bonds for a particular Dutch Auction Rate Period will be the rate established in accordance with the procedures set forth in the Indenture.

Long Term Rates and Long Term Rate Periods. If the Interest Rate Mode for the Bonds is the Long Term Rate, the interest rate on the Bonds for a particular Long Term Rate Period will be the rate established by the Remarketing Agent no later than 12:00 noon (New York City time) on the Business Day preceding the first day of such Long Term Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof. The Company will establish the duration of the Long Term Rate Period at the time that it directs the Conversion of the Interest Rate Mode to the Long Term Rate, and thereafter each successive Long Term Rate Period will be the same as the Long Term Rate Period so established by the Company until a different Long Term Rate Period is specified by the Company in accordance with the Indenture (in which case the duration of that Long Term Rate Period will control succeeding Long Term Rate Periods), subject in all cases to the occurrence of a Conversion Date or the maturity of the Bonds. Each Long Term Rate Period will be more than one year in duration, will be for a period which is an integral multiple of six months and will end on the day next preceding an Interest Payment Date; provided that if a Long Term Rate Period commences on a date other than an April 1 or October 1, such Long Term Rate Period may be for a period which is not an integral multiple of six months but will be of a duration as close as possible to (but not in excess of) such Long Term Rate Period established by the Company and will terminate on a day preceding an Interest Payment Date, and each successive Long Term Rate Period thereafter will be for the full period established by the Company until a different Long Term Rate Period is specified by the Company in accordance with the Indenture or until the occurrence of a Conversion Date or the maturity of the Bonds; provided further that no Long Term Rate Period will extend beyond the final maturity date of the Bonds.

Failure to Determine Rate. If for any reason the interest rate for a Bond is not determined by the Remarketing Agent, except as described below under "— Conversion of Interest Rate Modes and Changes of Long Term Rate Periods — Change of Long Term Rate Period" and "— Cancellation of Conversion of Interest Rate Mode," the interest rate for such Bond for the next succeeding interest rate period will be the interest rate in effect for such Bond for the preceding interest rate period and, pursuant to the terms of the Indenture, there will be no change in the then applicable Long Term Rate Period or any Conversion from the then applicable Interest Rate Mode. Notwithstanding the foregoing, if for any reason the interest rate for a Bond bearing interest at a Flexible Rate is not determined by the Remarketing Agent, the interest rate for such Bond for the next succeeding Interest Period will be equal to The Bond

Market Association Municipal Swap Index™ (the "Municipal Index") as defined in the Indenture and the Interest Period for such Bond will extend through the day preceding the next Business Day, until the Trustee is notified of a new Flexible Rate and Flexible Rate Period determined for such Bond by the Remarketing Agent.

Conversion of Interest Rate Modes and Changes of Long Term Rate Periods

Method of Conversion. The Interest Rate Mode for the Bonds is subject to Conversion from time to time, in whole but not in part, on the dates specified below under "— Limitations on Conversion," at the option of the Company, upon notice from the Bond Registrar to the registered owners of the Bonds, as described below. With any notice of Conversion, the Company must also deliver to the Bond Registrar and the Credit Facility Issuer an opinion of Bond Counsel stating that such Conversion is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, other than a Conversion from the Daily Rate Period to the Weekly Rate Period or from the Weekly Rate Period to the Daily Rate Period.

Conditions Precedent to Conversions. The following conditions are applicable to Conversions of the Bonds:

(a) any Credit Facility to be held by the Trustee after the Conversion Date must be sufficient to cover the principal of and accrued interest on the outstanding Bonds for the maximum Interest Period permitted for that particular Interest Rate Mode plus 10 days at the maximum interest rate, and if a Credit Facility is to be held by the Trustee after the Conversion of the Bonds to a Long Term Rate Period, that Credit Facility must also extend for the entire Long Term Rate Period plus 10 days at the maximum interest rate; and

(b) if a Credit Facility is then in effect and the purchase price of the Bonds under the Indenture includes any premium, the Trustee will be entitled to draw on that Credit Facility in an aggregate amount sufficient to pay the applicable purchase price (including such premium) or, in the alternative, available moneys will be available in the necessary amount and are applied to the payment of such premium.

Limitations on Conversion. Any Conversion of the Interest Rate Mode for the Bonds must be in compliance with the following conditions: (i) the Conversion Date must be a date on which the Bonds are subject to optional redemption (see "— Redemptions — Optional Redemption" below); provided that any Conversion from the Daily Rate Period to a Weekly Rate Period or from the Weekly Rate Period to the Daily Rate Period must be on a Wednesday and, if the Conversion is to or from a Dutch Auction Rate Period, the Conversion Date must be the last Interest Payment Date in respect of that Dutch Auction Rate Period; (ii) if the proposed Conversion Date would not be an Interest Payment Date but for the Conversion, the Conversion Date must be a Business Day; (iii) if the Conversion is from the Flexible Rate, (a) the Conversion Date may be no earlier than the latest Interest Payment Date established prior to the giving of notice to the Remarketing Agent of such proposed Conversion and (b) no further Interest Payment Date may be established while the Interest Rate Mode is then the Flexible Rate if such Interest Payment Date would occur after the effective date of that Conversion; and

(iv) after a determination is made requiring mandatory redemption of all Bonds pursuant to the Indenture (see "— Redemptions" below), no change in the Interest Rate Mode may be made prior to such mandatory redemption.

__Change of Long Term Rate Period__. The Company may change from one Long Term Rate Period to another Long Term Rate Period on any Business Day on which the Bonds are subject to optional redemption as described under "— Redemptions — Optional Redemption" below upon notice from the Bond Registrar to the owners of Bonds as described below. With any notice of such change, the Company must also deliver an opinion of Bond Counsel stating that such change is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. Notwithstanding the foregoing, the Long Term Rate Period will not be changed to a new Long Term Rate Period if (A) the Remarketing Agent has not determined the interest rate for the new Long Term Rate Period in accordance with the terms of the Indenture or (B) the Bond Registrar receives written notice from Bond Counsel prior to the effective date of the change to the effect that the opinion of such Bond Counsel required under the Indenture has been rescinded. Upon the occurrence of any of the events described in the preceding sentence, the Bonds will bear interest at the Weekly Rate commencing on the date which would have been the effective date of the proposed change of Long Term Rate Period, subject to the provisions described below under "— Cancellation of Conversion of Interest Rate Mode."

__Notice to Owners of Conversion of Interest Rate Mode or of Change of Long Term Rate Period__. The Bond Registrar will notify each registered owner of the Conversion or change of Long Term Rate Period, as applicable, by first class mail at least 15 days (30 days in the case of Conversion from or to the Semi-Annual Rate, the Annual Rate or a Long Term Rate or in the case of a change in the Long Term Rate Period) but not more than 45 days before each Conversion Date or each effective date of a change in the Long Term Rate Period. The notice will state those matters required to be set forth therein under the Indenture.

__Cancellation of Conversion of Interest Rate Mode__. Notwithstanding the foregoing, no Conversion will occur if (A) the Remarketing Agent has not determined the initial interest rate for the new Interest Rate Mode in accordance with the terms of the Indenture, (B) the Bonds that are to be purchased are not remarketed or sold by the Remarketing Agent or (C) the Bond Registrar receives written notice from Bond Counsel prior to the opening of business on the effective date of Conversion to the effect that the opinion of such Bond Counsel required under the Indenture has been rescinded. If such Conversion fails to occur, such Bonds in the Dutch Auction Rate will remain in such Interest Rate Mode and Bonds in any other Interest Rate Mode will automatically be converted to the Weekly Rate (with the first period adjusted in length so that the last day of such period will be a Tuesday) at the rate determined by the Remarketing Agent on the failed Conversion Date; provided, that there must be delivered to the Issuer, the Trustee, the Tender Agent, the Company, the Credit Facility Issuer and the Remarketing Agent an opinion of Bond Counsel to the effect that determining the interest rate to be borne by the Bonds at a Weekly Rate is authorized or permitted by the Act and is authorized under the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. If such opinion is not delivered on the failed Conversion Date, the Bonds will bear interest for a Rate Period of the same type and of substantially the same length as the Rate Period in effect prior to the failed Conversion Date at a rate of interest determined by the Remarketing Agent on the failed Conversion Date (or if shorter, the Rate Period ending on the date before the maturity date); provided that if the Bonds then bear interest at the Long Term Rate, and if such opinion is not delivered on the date which would have been the effective date of a new Long Term Rate Period, the Bonds will bear interest at the Annual Rate, commencing on such date, at an Annual Rate determined by the Remarketing Agent on such date. If the proposed Conversion of Bonds fails as described herein, any mandatory purchase of such Bonds will remain effective.

Purchases of Bonds on Demand of Owner

If the Bonds are in the book-entry-only system, demands for purchase may be made by Beneficial Owners only through such Beneficial Owner's Direct Participant (as defined under the caption "—Book-Entry-Only System"). If the Bonds are in certificated form, demands for purchase may be made only by registered owners. When the Interest Rate Mode is the Dutch Auction Rate, the Bonds are not subject to purchase on demand of the owners thereof.

Daily Rate. If the Interest Rate Mode for the Bonds is the Daily Rate, any Bond will be purchased on the demand of the registered owner thereof on any Business Day during a Daily Rate Period at a purchase price equal to the principal amount thereof plus accrued interest, if any, to the Purchase Date upon written notice or telephonic notice (to be immediately confirmed in writing) to the Tender Agent at its principal office not later than 10:00 a.m. (New York City time) on such Business Day.

Weekly Rate. If the Interest Rate Mode for the Bonds is the Weekly Rate, any Bond will be purchased on the demand of the registered owner thereof on any Business Day during a Weekly Rate Period at a purchase price equal to the principal amount thereof plus accrued interest, if any, to the Purchase Date upon written notice to the Tender Agent at its principal office at or before 5:00 p.m. (New York City time) on a Business Day not later than the seventh day prior to the Purchase Date.

Semi-Annual Rate. If the Interest Rate Mode for the Bonds is the Semi-Annual Rate, any Bond will be purchased on the demand of the registered owner thereof on any Interest Payment Date for a Semi-Annual Rate Period at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Annual Rate. If the Interest Rate Mode for the Bonds is the Annual Rate, any Bond will be purchased on the demand of the registered owner thereof on the final Interest Payment Date for such Annual Rate Period at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Long Term Rate. If the Interest Rate Mode for the Bonds is the Long Term Rate, any Bond will be purchased on the demand of the registered owner thereof on the final Interest Payment Date for such Long Term Rate Period (unless such date is the final maturity date) at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Limitations on Purchases on Demand of Owner. Notwithstanding the foregoing, there will be no purchase of (a) a portion of any Bond unless the portion to be purchased and the portion to be retained each will be in an authorized denomination or (b) any Bond upon the demand of the registered owner if an Event of Default under the Indenture with respect to the payment of principal of, interest on, or purchase price of, the Bonds has occurred and is continuing. Also, if the Interest Rate Mode for the Bonds is the Flexible Rate, the Bonds will not be subject to purchase on the demand of the registered owners thereof, but each Bond will be subject to mandatory purchase on each Conversion Date and on the Interest Payment Date with respect to such Bond, as described below under the caption "— Mandatory Purchases of Bonds."

Notice Required for Purchases. Any written notice delivered to the Tender Agent by an owner demanding the purchase of Bonds must (A) be delivered by the time and dates specified above, (B) state the number and principal amount (or portion thereof) of such Bond to be purchased, (C) state the Purchase Date on which such Bond is to be purchased, (D) irrevocably request such purchase and state that the owner agrees to deliver such Bond, duly endorsed in blank for transfer, with all signatures guaranteed, to the Tender Agent at or prior to 11:00 a.m. (1:00 p.m. if a tender during a Daily Rate Period and 12:00 noon if a tender during a Weekly Rate Period) (New York City time) on such Purchase Date.

Mandatory Purchases of Bonds

Mandatory Purchase on Conversion Dates or Change by the Company in Long Term Rate Period. The Bonds will be subject to mandatory purchase at a purchase price equal to the principal amount thereof, plus accrued interest, if any, to the Purchase Date, plus, if the Interest Rate Mode is the Long Term Rate, the redemption premium, if any, which would be payable as described under "— Redemptions — Optional Redemption" below, if the Bonds were redeemed on the Purchase Date (A) on each Conversion Date and (B) on the effective date of any change by the Company of the Long Term Rate Period. Such tender and purchase will be required even if the change in Long Term Rate Period or the Conversion is canceled pursuant to the Indenture.

Mandatory Purchase on Each Interest Payment Date for Flexible Rate Period. Whenever the Interest Rate Mode for the Bonds is the Flexible Rate, each Bond will be subject to mandatory purchase at a purchase price equal to the principal amount thereof, without premium, plus accrued interest, if any, to the Purchase Date, on each Interest Payment Date that interest on such Bond is payable at an interest rate determined for the Flexible Rate. Owners of Bonds will receive no notice of such mandatory purchase.

Mandatory Purchase on Day after End of the Semi-Annual Rate Period, the Annual Rate Period or the Long Term Rate Period. Whenever the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the Annual Rate or the Long Term Rate, such Bonds will be subject to mandatory purchase on the Business Day following the end of each Semi-Annual Rate Period, Annual Rate Period or Long Term Rate Period, as the case may be, for such Bond at a purchase price equal to the principal amount thereof plus accrued interest, if any, to such date.

Mandatory Purchase upon Delivery, Cancellation, Substitution, Extension, Termination or Expiration of Any Credit Facility or Replacement with an Alternate Credit Facility. If, at the option of the Company, a Credit Facility (other than the initial Letter of Credit) is delivered with respect to the Bonds subsequent to the Reoffering Date, the Bonds will be subject to mandatory tender for purchase at a purchase price equal to 100% of the principal amount thereof, plus accrued interest, if any, to the Purchase Date on the date of the delivery of the Credit Facility. In addition, if the Bonds are secured by a Credit Facility, the Bonds will be subject to mandatory tender for purchase at a purchase price equal to 100% of the principal amount thereof, plus accrued interest, if any, (A) on the Interest Payment Date at least five days prior to the date of the cancellation of or the expiration of the term of the then current Credit Facility and (B) on the Interest Payment Date on which a Credit Facility is replaced with an Alternate Credit Facility.

Notice to Owners of Mandatory Purchases. Notice to owners of a mandatory purchase of Bonds (except for mandatory purchase on each Interest Payment Date for Flexible Rate Periods) will be given by the Bond Registrar, by first class mail at least 15 days but not more than 45 days before the Purchase Date; provided, however, as an alternative to the foregoing, if DTC or its nominee is the registered owner of the Bonds, notice may be given to DTC not less than five days before the Purchase Date. The notice of mandatory purchase will state those matters required to be set forth therein under the Indenture. No notice of mandatory purchase will be given in connection with a mandatory purchase on an Interest Payment Date for a Flexible Rate Period.

Remarketing and Purchase of Bonds

The Indenture provides that, subject to the terms of a Remarketing Agreement with the Company, the Remarketing Agent will use its reasonable best efforts to offer for sale Bonds purchased upon demand of the owners thereof and, unless otherwise instructed by the Company and with the consent of any Credit Facility Issuer, upon mandatory purchase, provided that Bonds will not be remarketed upon the occurrence and continuance of certain Events of Default under the Indenture, except in the sole discretion of the Remarketing Agent. Each such sale will be at a price equal to the principal amount thereof, plus interest accrued to the date of sale. The Remarketing Agent, the Trustee, the Paying Agent, the Bond Registrar or the Tender Agent each may purchase any Bonds offered for sale for its own account.

On each date Bonds are to be purchased pursuant to optional or mandatory purchase under the Indenture, such Bonds will be purchased from the following sources in the order of priority indicated, provided that funds derived from clause (c) may not be combined with the funds derived from clauses (a) or (b) to purchase any Bonds:

(a) proceeds of the remarketing of such Bonds to persons other than the Company, its affiliates or the Issuer and furnished to the Tender Agent by the Remarketing Agent and deposited directly into, and held in, the Remarketing Proceeds Subaccount of the Purchase Fund established with the Tender Agent under the Indenture;

(b) proceeds of the Credit Facility, if any, furnished by the Trustee, as Tender Agent, and deposited by the Tender Agent directly into, and held in, the Credit Facility Subaccount of the Purchase Fund; and

(c) moneys paid by the Company (including the proceeds of the remarketing of the Bonds to the Company, its affiliates or the Issuer) to pay the purchase price to the Tender Agent.

If there is no Credit Facility in operation to secure the Bonds, any Bonds will be purchased with any moneys made available by the Company, including proceeds from the remarketing of the Bonds.

Payment of Purchase Price

When a book-entry-only system is not in effect, payment of the purchase price of any Bond will be payable (and delivery of a replacement Bond in exchange for the portion of any Bond not purchased if such Bond is purchased in part will be made) on the Purchase Date upon delivery of such Bond to the Tender Agent on such Purchase Date; provided that such Bond must be delivered to the Tender Agent: (i) at or prior to 12:00 noon (New York City time), in the case of Bonds delivered for purchase during a Weekly Rate Period or Flexible Rate Period, (ii) at or prior to 1:00 p.m. (New York City time), in the case of Bonds delivered for purchase during a Daily Rate Period or (iii) at or prior to 11:00 a.m. (New York City time), in the case of Bonds delivered for purchase during a Semi-Annual Rate Period, Annual Rate Period or Long Term Rate Period. If the date of such purchase is not a Business Day, the purchase price will be payable on the next succeeding Business Day.

Any Bond delivered for payment of the purchase price must be accompanied by an instrument of transfer thereof in form satisfactory to the Tender Agent executed in blank by the registered owner thereof and with all signatures guaranteed. The Tender Agent may refuse to accept delivery of any Bond for which an instrument of transfer satisfactory to it has not been provided and has no obligation to pay the purchase price of such Bond until a satisfactory instrument is delivered.

If the registered owner of any Bond (or portion thereof) that is subject to purchase pursuant to the Indenture fails to deliver such Bond with an appropriate instrument of transfer to the Tender Agent for purchase on the Purchase Date, and if the Tender Agent is in receipt of the purchase price therefor, such Bond (or portion thereof) nevertheless will be deemed purchased on the Purchase Date thereof. Any owner who so fails to deliver such Bond for purchase on (or before) the Purchase Date will have no further rights thereunder, except the right to receive the purchase price thereof from those moneys deposited with the Tender Agent in the Purchase Fund pursuant to the Indenture upon presentation and surrender of such Bond to the Tender Agent properly endorsed for transfer in blank with all signatures guaranteed.

When a book-entry-only system is in effect, the requirement for physical delivery of the Bonds will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on the records of DTC to the participant account of the Tender Agent.

Redemptions

Optional Redemption.

(a) Whenever the Interest Rate Mode for the Bonds is the Daily Rate or the Weekly Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof, plus interest accrued, if any, to the redemption date, on any Business Day.

(b) Whenever the Interest Rate Mode for a Bond is the Flexible Rate, such Bond will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof on any Interest Payment Date for that Bond.

(c) Whenever the Interest Rate Mode for the Bonds is the Dutch Auction Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, on the Business Day immediately succeeding any auction date, at a redemption price of 100% of the principal amount thereof, together with accrued interest to the redemption date.

(d) Whenever the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof on any Interest Payment Date.

(e) Whenever the Interest Rate Mode for the Bonds is the Annual Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof on the final Interest Payment Date for each Annual Rate Period.

(f) Whenever the Interest Rate Mode for the Bonds is the Long Term Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, (1) on the final Interest Payment Date for the then-current Long Term Rate Period at a redemption price of 100% of the principal amount thereof and (2) prior to the end of the then-current Long Term Rate Period at any time during the redemption periods and at the redemption prices set forth below, plus in each case interest accrued, if any, to the redemption date:

Original Length of Current Long Term Rate Period (Years)	Commencement of Redemption Period	Redemption Price as Percentage of Principal
More than or equal to 11 years	First Interest Payment Date on or after the tenth anniversary of commencement of Long Term Rate Period	100%
Less than 11 years	Non-callable	Non-callable

Subject to certain conditions, including provision of an opinion of Bond Counsel that a change in the redemption provisions of the Bonds will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, the redemption periods and redemption prices may be revised, effective as of the Conversion Date, the date of a change in the Long Term Rate Period or a Purchase Date on the final Interest Payment Date during a Long Term Rate Period, to reflect Prevailing Market Conditions on such date as determined by the Remarketing Agent in its judgment.

Extraordinary Optional Redemption in Whole. The Bonds may be redeemed by the Issuer in whole at any time at 100% of the principal amount thereof plus accrued interest to the redemption date upon the exercise by the Company of an option under the Loan Agreement to prepay the loan if any of the following events shall have occurred within 180 days preceding the giving of written notice by the Company to the Trustee of such election:

(i) if in the judgment of the Company, unreasonable burdens or excessive liabilities have been imposed upon the Company after the issuance of the Bonds with respect to the Project or the operation thereof, including without limitation federal, state or other ad valorem property, income or other taxes not imposed on the date of the Loan Agreement, other than ad valorem taxes levied upon privately owned property used for the same general purpose as the Project;

(ii) if the Project or a portion thereof or other property of the Company in connection with which the Project is used has been damaged or destroyed to such an extent so as, in the judgment of the Company, to render the Project or such other property of the Company in connection with which the Project is used unsatisfactory to the Company for its intended use, and such condition continues for a period of six months;

(iii) there has occurred condemnation of all or substantially all of the Project or the taking by eminent domain of such use or control of the Project or other property of the Company in connection with which the Project is used so as, in the judgment of the Company, to render the Project or such other property of the Company unsatisfactory to the Company for its intended use;

(iv) in the event changes, which the Company cannot reasonably control, in the economic availability of materials, supplies, labor, equipment or other properties or things necessary for the efficient operation of the generating station where the Project is located have occurred, which, in the judgment of the Company, render the continued operation of such generating station or any generating unit at such station uneconomical; or changes in circumstances after the issuance of the Bonds, including but not limited to changes in solid waste abatement, control and disposal requirements, have occurred such that the Company determines that use of the Project is no longer required or desirable;

(v) the Loan Agreement has become void or unenforceable or impossible of performance by reason of any changes in the Constitution of the Commonwealth of Kentucky or the Constitution of the United States of America or by reason of legislative or administrative action (whether state or federal) or any final decree, judgment or order of any court or administrative body, whether state or federal; or

(vi) a final order or decree of any court or administrative body after the issuance of the Bonds requires the Company to cease a substantial part of its operation at the generating station where the Project is located to such extent that the Company will be prevented from carrying on its normal operations at such generating station for a period of six months.

Extraordinary Optional Redemption in Whole or in Part. The Bonds are also subject to redemption in whole or in part at 100% of the principal amount thereof plus accrued interest to the redemption date at the option of the Company in an amount not to exceed the net proceeds received from insurance or any condemnation award received by the Issuer or the Company in the event of damage, destruction or condemnation of all or a portion of the Project, subject to receipt of an opinion of Bond Counsel that such redemption will not adversely affect the exclusion of interest on any of the Bonds from gross income for federal income tax purposes, and such net proceeds must be applied to reimburse the Credit Facility Issuer for drawings under the Credit Facility to redeem the Bonds. See "Summary of the Loan Agreement — Maintenance; Damage, Destruction and Condemnation." Such redemption may occur at any time, provided that if such event occurs while the Interest Rate Mode for the Bonds is the Daily Rate, Weekly Rate, Flexible Rate or Semi-Annual Rate, such redemption must occur on a date on which the Bonds are otherwise subject to optional redemption as described above.

Mandatory Redemption; Determination of Taxability. The Bonds are required to be redeemed by the Issuer, in whole, or in such part as described below, at a redemption price equal to 100% of the principal amount thereof, without redemption premium, plus accrued interest, if any, to the redemption date, within 180 days following a "Determination of Taxability." As used herein, a "Determination of Taxability" means the receipt by the Trustee of written notice from a current or former registered owner of a Bond or from the Company or the Issuer of (A) the issuance of a published or private ruling or a technical advice memorandum by the Internal Revenue Service in which the Company participated or has been given the opportunity to participate, and which ruling or memorandum the Company, in its discretion, does not contest or from which no further right of administrative or judicial review or appeal exists, or (B) a final determination from which no further right of appeal exists of any court of competent jurisdiction in the United States in a proceeding in which the Company has participated or has been a party, or has been given the opportunity to participate or be a party, in each case, to the effect that as a result of a failure by the Company to perform or observe any covenant or agreement or the inaccuracy of any representation contained in the Loan Agreement or any other agreement or certificate delivered in connection with the Bonds, the interest on the Bonds is included in the gross income of the owners thereof for federal income tax purposes, other than with respect to a person who is a "substantial user" or a "related person" of a substantial user within the meaning of the Section 147 of Internal Revenue Code of 1986, as amended (the "Code"); provided, however, that no such Determination of Taxability shall be considered to exist as a result of the Trustee receiving notice from a current or former registered owner of a Bond or from the Issuer unless (A) the Issuer or the registered owner or former registered owner of the Bond involved in such proceeding or action (1) gives the Company and the Trustee prompt notice of the commencement thereof, and (2) (if the Company agrees to pay all expenses in connection therewith) offers the Company the opportunity to control unconditionally the defense thereof, and (B) either (1) the Company does not agree within 30 days of receipt of such offer to pay such expenses and liabilities and to control such defense, or (2) the Company shall exhaust or choose not to exhaust all available proceedings for the contest, review, appeal or rehearing of such decree, judgment or action which the Company determines to be appropriate. No Determination of Taxability described above will result from the inclusion of interest on any Bond in the computation of minimum or indirect taxes. All of the Bonds are required to be redeemed upon a Determination of Taxability as described above unless, in the opinion of Bond Counsel, redemption of a portion of such Bonds would have the result that interest payable on the remaining Bonds outstanding after the redemption would not be so included in any such gross income.

In the event any of the Issuer, the Company or the Trustee has been put on notice or becomes aware of the existence or pendency of any inquiry, audit or other proceedings relating to the Bonds being conducted by the Internal Revenue Service, the party so put on notice is required to give immediate written notice to the other parties of such matters. Promptly upon learning of the occurrence of a Determination of Taxability (whether or not the same is being contested), or any of the events described above, the Company is required to give notice thereof to the Trustee and the Issuer.

If the Internal Revenue Service or a court of competent jurisdiction determines that the interest paid or to be paid on any Bond (except to a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) is or was includable in the gross income of the recipient for federal income tax purposes for reasons other than as a result of a failure by the Company to perform or observe any of its covenants, agreements or representations in the Loan Agreement or any other agreement or certificate delivered in connection therewith, the Bonds are not subject to redemption. In such circumstances, Bondholders would continue to hold their Bonds, receiving principal and interest at the applicable rate as and when due, but would be required to include such interest payments in gross income for federal income tax purposes. Also, if the lien of the Indenture is discharged or defeased prior to the occurrence of a final Determination of Taxability, Bonds will not be redeemed as described herein.

General Redemption Terms. So long as a Credit Facility is in effect in respect of the Bonds, the redemption price (including accrued interest) will be paid from drawings under such Credit Facility or from moneys which otherwise constitute Available Moneys under the Indenture. Notice of redemption will be given by mailing a redemption notice by first class mail to the registered owners of the Bonds to be redeemed not less than 30 days (15 days if the Interest Rate Mode for the Bonds is the Dutch Auction Rate, Flexible Rate, Daily Rate or Weekly Rate) but not more than 45 days prior to the redemption date. Any notice mailed as provided in the Indenture will be conclusively presumed to have been given, irrespective of whether the owner receives the notice. Failure to give any such notice by mailing or any defect therein in respect of any Bond will not affect the validity of any proceedings for the redemption of any other Bond. No further interest will accrue on the principal of any Bond called for redemption after the redemption date if funds sufficient for such redemption have been deposited with the Paying Agent as of the redemption date. If the provisions for discharging the Indenture set forth below under the caption, "Summary of the Indenture — Discharge of the Indenture" have not been complied with, any redemption notice will state that it is conditional on there being sufficient moneys to pay the full redemption price for the Bonds to be redeemed. So long as the Bonds are held in book-entry-only form, all redemption notices will be sent only to Cede & Co.

Book-Entry-Only System

Portions of the following information concerning DTC and DTC's book-entry-only system have been obtained from DTC. The Issuer, the Company and the Remarketing Agent make no representation as to the accuracy of such information.

Initially, DTC will act as securities depository for the Bonds and the Bonds initially will be issued solely in book-entry-only form to be held under DTC's book-entry-only system, registered in the name of Cede & Co. (DTC's partnership nominee). One fully registered bond in the aggregate principal amount of the Bonds will be deposited with DTC.

DTC, the world's largest depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934 (the "Exchange Act"). DTC holds and provides asset servicing for over 2.2 million issues of U.S. and non-U.S. equity, corporate and municipal debt issues, and money market instruments from over 100 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC, in turn, is owned by a number of Direct Participants of DTC and Members of the National Securities Clearing Corporation, Fixed Income Clearing Corporation, and Emerging Markets Clearing Corporation (NSCC, FICC and EMCC, also subsidiaries of DTCC), as well as by the New York Stock Exchange, Inc., the American Stock Exchange LLC and the National Association of Securities Dealers, Inc. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants" and, together with "Direct Participants," "Participants"). DTC has Standard & Poor's highest rating: AAA. The DTC Rules applicable to its Participants are on file with the SEC. More information about DTC can be found at www.dtcc.com and www.dtc.org.

Purchases of the Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser of each Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Bonds are to be accomplished by entries made on the books of Direct or Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the Bonds, except in the event that use of the book-entry system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of Bonds with DTC and their registration in the name of Cede & Co. or such other nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Redemption notices shall be sent to DTC. If less than all of the Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant to be redeemed.

Neither DTC nor Cede & Co. (nor such other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Issuer as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal and interest payments on the Bonds will be made to Cede & Co. or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts, upon DTC's receipt of funds and corresponding detail information from the Issuer or the Trustee on the payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC nor its nominee, the Trustee, the Company or the Issuer, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Issuer or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

A Beneficial Owner shall give notice to elect to have its Bonds purchased or tendered, through its Participant, to the Tender Agent, and shall effect delivery of such Bonds by causing the Direct Participant to transfer the Participant's interest in the Bonds, on DTC's records, to the Tender Agent. The requirement for physical delivery of Bonds in connection with a demand for purchase or a mandatory purchase will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on DTC's records and followed by a book-entry credit of tendered Bonds to the Tender Agent's DTC account.

DTC may discontinue providing its services as securities depository with respect to the Bonds at any time by giving reasonable notice to the Issuer, the Company, the Tender Agent and the Trustee, or the Issuer, at the request of the Company, may remove DTC as the securities depository for the Bonds. Under such circumstances, in the event that a successor securities depository is not obtained, bond certificates are required to be delivered as described in the Indenture (see "— Revision of Book-Entry-Only System; Replacement Bonds" below). The Beneficial Owner, upon registration of certificates held in the Beneficial Owner's name, will become the registered owner of the Bonds.

So long as Cede & Co. is the registered owner of the Bonds, as nominee of DTC, references herein to the registered owners of the Bonds will mean Cede & Co. and will not mean the Beneficial Owners. Under the Indenture, payments made by the Trustee to DTC or its nominee will satisfy the Issuer's obligations under the Indenture, the Company's obligations under the Loan Agreement, to the extent of the payments so made. Beneficial Owners will not be, and will not be considered by the Issuer or the Trustee to be, and will not have any rights as, owners of Bonds under the Indenture.

The Trustee and the Issuer, so long as a book-entry-only system is used for the Bonds, will send any notice of redemption or of proposed document amendments requiring consent of registered owners and any other notices required by the document (including notices of Conversion and mandatory purchase) to be sent to registered owners only to DTC (or any successor securities depository) or its nominee. Any failure of DTC to advise any Direct Participant, or of any Direct Participant or Indirect Participant to notify the Beneficial Owner, of any such notice and its content or effect will not affect the validity of the redemption of the

Bonds called for redemption, the document amendment, the Conversion, the mandatory purchase or any other action premised on that notice.

The Issuer, the Company, the Trustee and the Remarketing Agent cannot and do not give any assurances that DTC will distribute payments on the Bonds made to DTC or its nominee as the registered owner or any redemption or other notices, to the Participants, or that the Participants or others will distribute such payments or notices to the Beneficial Owners, or that they will do so on a timely basis, or that DTC will serve and act in the manner described in this Reoffering Circular.

THE ISSUER, THE COMPANY, THE REMARKETING AGENT AND THE TRUSTEE WILL HAVE NO RESPONSIBILITY OR OBLIGATION TO ANY DIRECT PARTICIPANT, INDIRECT PARTICIPANT OR ANY BENEFICIAL OWNER OR ANY OTHER PERSON NOT SHOWN ON THE REGISTRATION BOOKS OF THE TRUSTEE AS BEING A REGISTERED OWNER WITH RESPECT TO: (1) THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC OR ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT; (2) THE PAYMENT OF ANY AMOUNT DUE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER IN RESPECT OF THE PRINCIPAL AMOUNT OR REDEMPTION OR PURCHASE PRICE OF OR INTEREST ON THE BONDS; (3) THE DELIVERY OF ANY NOTICE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER WHICH IS REQUIRED OR PERMITTED TO BE GIVEN TO REGISTERED OWNERS UNDER THE TERMS OF THE INDENTURE; (4) THE SELECTION OF THE BENEFICIAL OWNERS TO RECEIVE PAYMENT IN THE EVENT OF ANY PARTIAL REDEMPTION OF THE BONDS; OR (5) ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC AS REGISTERED OWNER.

Revision of Book-Entry-Only System; Replacement Bonds. In the event that DTC determines not to continue as securities depository or is removed by the Issuer, at the direction of the Company, as securities depository, the Issuer, at the direction of the Company, may appoint a successor securities depository reasonably acceptable to the Trustee. If the Issuer does not or is unable to appoint a successor securities depository, the Issuer will issue and the Trustee will authenticate and deliver fully registered Bonds, in authorized denominations, to the assignees of DTC or their nominees.

In the event that the book-entry-only system is discontinued, the following provisions will apply. The Bonds may be issued in denominations of $25,000 and integral multiples thereof, if the Interest Rate Mode is the Dutch Auction Rate; in denominations of $5,000 and integral multiples thereof, if the Interest Rate Mode is the Semi-Annual Rate, the Annual Rate or the Long Term Rate; in denominations of $100,000 and integral multiples of $5,000 in excess thereof, if the Interest Rate Mode is the Flexible Rate; and in denominations of $100,000 and integral multiples thereof, if the Interest Rate Mode is the Daily Rate or the Weekly Rate. Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the principal office of the Bond Registrar, accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond during the fifteen days before any mailing of a notice of redemption, after such Bond has been called for redemption in whole or in part, or after such Bond has been tendered or deemed tendered for optional or mandatory purchase as described under "— Purchases of Bonds on Demand of Owner" and "— Mandatory Purchases of Bonds." Registration of transfers and exchanges will be made without charge to the owners of Bonds, except that the Bond Registrar may require any owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

Security; Limitation on Liens

Payment of the principal of and interest and any premium on the Bonds are secured by an assignment by the Issuer to the Trustee of the Issuer's interest in and to the Loan Agreement and all payments to be made pursuant thereto (other than certain indemnification and expense payments and notification rights). Pursuant to the Loan Agreement, the Company will agree to pay, among other things, amounts sufficient to pay the aggregate principal amount of and premium, if any, on the Bonds, together with interest thereon as and when the same become due. The Company further will agree to make payments of the purchase price of the Bonds tendered for purchase to the extent that funds are not otherwise available therefor under the provisions of the Indenture.

The Bonds are unsecured general obligations of the Company, ranking on a parity with the Company's obligations under the Loan Agreement to make payments on the Bonds.

In the Loan Agreement, the Company covenants that it will not, so long as any of the Bonds are outstanding, issue, assume or guarantee any debt for borrowed money secured by any mortgage, security interest, pledge or lien ("mortgage") on any of the Company's operating property (as defined below), whether the Company owns it at the date hereof or acquires it later, unless the Company similarly secures its obligations under the Loan Agreement to make payments to the Trustee in sufficient amounts to pay the principal of, premium, if any, and interest required to be paid on the Bonds. This restriction will not apply to:

- mortgages on any property existing at the time the Company acquires the property or at the time the Company acquires the corporation owning the property;

- purchase money mortgages;

- specified governmental mortgages; or

- any extension, renewal or replacement (or successive extensions, renewals or replacements) of any mortgage referred to in the three clauses listed above, so long as the principal amount of indebtedness secured under this clause and not otherwise authorized by the clauses listed above, does not exceed the principal amount of indebtedness secured at the time of the extension, renewal or replacement.

In addition, the Company can also issue secured debt so long as the amount of the secured debt does not exceed the greater of 10% of net tangible assets or 10% of capitalization.

For purposes of this limitation on liens, "operating property" means (1) any interest in real property owned by the Company, and (2) any asset owned by the Company that is depreciable in accordance with generally accepted accounting principles.

The Letter of Credit

The following summarizes certain provisions of the Letter of Credit and the Reimbursement Agreement, to which reference is made for the detailed provisions thereof. Unless otherwise defined in this Reoffering Circular, capitalized terms in the following summary are used as defined in the Letter of Credit and the Reimbursement Agreement. The Company is permitted under the Indenture to deliver an Alternate Credit Facility to replace the Letter of Credit. Any such Alternate Credit Facility must meet certain requirements described in the Indenture.

The Letter of Credit

The Letter of Credit will be an irrevocable transferable direct pay letter of credit issued by the Bank in order to provide additional security for the payment of principal of, purchase price of, interest on and premium, if applicable, on any date when payments under the Bonds are due, including principal and interest payments and payments upon tender, redemption, acceleration or maturity of the Bonds. The Letter of Credit will provide for direct payments to or upon the order of the Trustee as set forth in the Letter of Credit in amounts sufficient to pay to or upon the order of the Trustee, upon request and in accordance with the terms thereof.

The Letter of Credit will be issued in an amount equal to the aggregate principal amount of the outstanding Bonds, plus an amount that represents interest accrued thereon at an assumed rate of 14% per annum for 45 days (the "Credit Amount"). The Trustee, upon compliance with the terms of the Letter of Credit, is authorized to draw up to (a) an amount sufficient (i) to pay principal of the Bonds, when due, whether at maturity or upon redemption or acceleration, and (ii) to pay the portion of the purchase price of the Bonds delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed (a "Liquidity Drawing") equal to the principal amount of the Bonds, plus (b) an amount not to exceed 45 days of accrued interest on such Bonds at an assumed rate of 14% per annum (i) to pay interest on the Bonds, when due, and (ii) to pay the portion of the purchase price of the Bonds, delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed, equal to the interest accrued, if any, on the Bonds.

The amount available under the Letter of Credit will be automatically reduced by the amount of any drawing thereunder, subject to reinstatement as described below. With respect to a drawing by the Trustee solely to pay interest on the Bonds on an Interest Payment Date, the amount available under the Letter of Credit will be automatically reinstated in the amount of such drawing effective on the earlier of (i) receipt by the Bank from the Company of reimbursement of any drawing solely to pay interest in full or (ii) at the opening of business on the eleventh calendar day after the date the Bank honors such drawing, unless the Trustee has received written notice from the Bank by the tenth calendar day after the date the Bank honors such drawing the Bank is not so reinstating the available amount due to the Company's failure to reimburse the Bank for such drawing in full, or that an event of default has occurred and is continuing under the Reimbursement Agreement and, in either case, directing, an acceleration of the Bonds pursuant to the Indenture. With respect to a Liquidity Drawing under the Letter of Credit, the amount available under the Letter of Credit will be automatically reduced by the principal amount of the Bonds purchased with the proceeds of such drawing plus the amount of accrued interest on such Bonds. In the event of the remarketing of the Bonds purchased with the proceeds of a Liquidity Drawing, the amount available under the Letter of Credit will be automatically reinstated upon receipt by the Bank or the Trustee on the Bank's behalf of an amount equal to such principal amount plus accrued interest.

The Letter of Credit will terminate on the earliest to occur of:

(a) the Bank's close of business on December 16, 2009 (such date, as extended from time to time in accordance with the Letter of Credit is defined as the "Stated Expiration Date");

(b) the Bank's close of business on the date which is five Business Days following the date of receipt by the Bank of a certificate from the Trustee certifying that (a) no Bonds remain Outstanding within the meaning of the Indenture, (b) all drawings required to be made under the Indenture and available under the Letter of Credit have been made and honored, (c) an Alternate Credit Facility has been delivered to the Trustee in accordance with the Indenture to replace the Letter of Credit or (d) all of the outstanding Bonds were converted to Bonds bearing interest at a rate other than the Daily Rate or the Weekly Rate;

(c) the Bank's close of business on the date of receipt by the Bank of a certificate from the Trustee confirming that the Trustee is required to terminate the Letter of Credit in accordance with the terms of the Indenture; or

(d) the date on which the Bank receives and honors an acceleration drawing certificate.

The Reimbursement Agreement

Pursuant to the Reimbursement Agreement, the Company is obligated to reimburse the Bank for all amounts drawn under the Letter of Credit, and to pay interest on all such amounts. The Company has also agreed to pay the Bank a periodic fee for issuing and maintaining the Letter of Credit.

The Reimbursement Agreement imposes various covenants and agreements, including various financial and operating covenants, on the Company. Such covenants include, but are not limited to, covenants relating to (i) inspection of the books and financial records of the Company; (ii) creation of liens; (iii) liquidations, mergers, consolidations or sales of all or substantially all of the Company's assets; and (iv) disposition of assets. Any such covenants may be amended, waived or modified at any time by the Bank and without the consent of the

Trustee or the holders of the Bonds. Under certain circumstances, the failure of the Company to comply with such covenants may result in a mandatory tender or acceleration of the Bonds.

The following events will constitute an "event of default" under the Reimbursement Agreement:

(a) nonpayment of certain fees and other amounts required to be paid or reimbursed by the Company under the Reimbursement Agreement to the Bank within five days after the same was required to be paid;

(b) any representation or warranty made or deemed made by or on behalf of the Company or any of its Significant Subsidiaries to the Bank under or in connection with the Reimbursement Agreement or any other Transaction Document, any advance or any certificate or information delivered pursuant to or in connection with the Reimbursement Agreement or any other Transaction Document, was false or misleading in any material respect as of the time it was made or furnished;

(c) an "event of default" (not due to the Bank's failure to properly honor a drawing on the Letter of Credit) occurred under the Indenture or any of the other Transaction Documents and any applicable grace period has expired;

(d) the breach by the Company or any of its Significant Subsidiaries of any of the terms or provisions of certain covenants contained in the Reimbursement Agreement including, but not limited to, covenants relating to the provision of notice to the Bank regarding an "event of default" or "default" under the Reimbursement Agreement, the corporate existence and license or qualification and good standing of the Company in jurisdictions in which it owns or leases property, the creation of liens, the liquidation, merger, consolidation or sale of all or substantially all of the assets of the Company and the disposition of assets;

(e) the breach by the Company or any of its Significant Subsidiaries (other than a breach which constitutes a "default" described above) of any of the terms or provisions of the Reimbursement Agreement or any Security Document that is not remedied within thirty (30) days after an executive officer of the Company has actual knowledge of such default or written notice of such default has been given to the Company by the Bank;

(f) the Bonds cease to be valid for any reason;

(g) a default or event of default has occurred at any time under the terms of any other agreement involving borrowed money or the extension of credit or any other Indebtedness under which the Company or any of its Significant Subsidiaries may be obligated for the payment of $50,000,000 or more in the aggregate, and such breach, default or event of default continues beyond any period of grace permitted with respect thereto and as a result thereof such Indebtedness is accelerated, becomes due or is otherwise required to be repurchased or redeemed prior to the scheduled date of maturity thereof;

(h) a proceeding has been instituted in a court having jurisdiction in the premises seeking a decree or order for relief in respect of the Company or any Significant Subsidiary in an involuntary case under any applicable bankruptcy, insolvency, reorganization or other similar law now or hereafter in effect, or for the appointment of a receiver, liquidator, assignee, custodian, trustee, sequestrator, conservator (or similar official) of the Company or any Significant Subsidiary for any substantial part of its property, or for the winding-up or liquidation of its affairs, and such proceeding shall remain undismissed or unstayed and in effect for a period of sixty (60) consecutive days; such court shall enter a decree or order granting any of the relief sought in such proceeding; or the Company or any Significant Subsidiary shall consent, approve or otherwise acquiesce in any of the actions sought in such proceeding;

(i) the Company or any Significant Subsidiary shall commence a voluntary case under any applicable bankruptcy, insolvency, reorganization or other similar law now or hereafter in effect, shall consent to the entry of an order for relief in an involuntary case under any such law, or shall consent to the appointment or taking possession by a receiver, liquidator, assignee, custodian, trustee, sequestrator, conservator (or other similar official) of itself or for any substantial part of its property or shall make a general assignment for the benefit of creditors, or shall fail generally to pay its debts as they become due, or shall take any action in furtherance of any of the foregoing;

(j) without the application, approval or consent of the Company or any of its Significant Subsidiaries, a receiver, trustee, examiner, liquidator or similar official shall be appointed for the Company or any of its Significant Subsidiaries, or for any substantial portion of its Property, or a proceeding described in paragraph (h) above has been instituted against the Company or any of its Significant Subsidiaries, and such appointment continues undischarged or such proceeding continues undismissed or unstayed for a period of 60 consecutive days;

(k) any of the following occurs: (i) any Reportable Event which constitutes grounds under Section 4042 of ERISA for the termination of any Plan by the PBGC or the appointment of a trustee to administer or liquidate any Plan, shall have occurred and be continuing; (ii) a notice of intent to terminate any Plan shall have been filed with the PBGC under Section 4041 of ERISA; (iii) the PBGC shall give notice under Section 4042 of ERISA of its intent to institute proceedings to terminate any Plan or Plans or to appoint a trustee to administer or liquidate any Plan; (iv) the Company or any member of the ERISA Group shall fail to make any contributions when due to a Plan or a Multiemployer Plan; (v) the Company or any member of the ERISA Group shall make any amendment to a Plan with respect to which security is required under Section 307 of ERISA; (vi) the Company or any member of the ERISA Group shall withdraw completely or partially from a Multiemployer Plan pursuant to Subtitle E of Title IV of ERISA; or (vii) the Company or any member of the ERISA Group shall withdraw within the meaning of Section 4063 of ERISA (or shall be deemed under Section 4062(e) of ERISA to withdraw) from a Multiple Employer Plan; and, with respect to any of such events specified in clause (i), (ii), (iii), (iv), (v), (vi) or (vii), such occurrence would be reasonably likely to result in a Material Adverse Effect;

(l) any final judgment(s) or order(s) for the payment of money shall be entered against the Company or any of its Significant Subsidiaries by a court having jurisdiction in the premises which judgment is not discharged, vacated, bonded or stayed pending appeal within a period of thirty (30) days from the date of entry if the aggregate uninsured amount of all such judgments and orders exceeds $50,000,000;

(m) the Company or any of its Significant Subsidiaries ceases to conduct business (other than as permitted hereunder) or the Company is enjoined, restrained or in any way prevented by court order from conducting all or any material part of its business and such injunction, restraint or other preventive order is not dismissed within thirty (30) days after the entry thereof; or

(n) E.ON AG fails to own, directly or indirectly, at least seventy-five percent (75%) of the outstanding Voting Capital of the Company.

For purposes of the foregoing:

"Bond Documents" means the Indenture, the Custody Agreement, the Loan Agreement, the Bonds and the Remarketing Agreement.

"Material Adverse Effect" means (i) a material adverse change in the business, property, condition (financial or otherwise), operations or results of operations of the Company and its subsidiaries taken as a whole, (ii) a material adverse change in the ability of the Company to perform its obligation under the Transaction Documents or (iii) a material adverse change in the validity or enforceability of any of the Transaction Documents or the rights or remedies of the Bank thereunder.

"Security Documents" means the Custody, Pledge and Security Agreement dated as of December 17, 2008 among the Trustee, the Company and the Bank with respect to any Bond purchased during the period from and including the date of its purchase with proceeds of a Liquidity Drawing to but excluding the date on which such Bond is purchased by any person as a result of a remarketing of such Bond pursuant to the Remarketing Agreement and the Indenture.

"Transaction Documents" means, collectively, the Reimbursement Agreement, Bond Documents, the Security Documents and all other operative documents relating to the issuance, sale and securing of the Bonds (including without limitation any document(s) or instrument(s) through which the Bonds are now or hereafter collateralized, such as mortgages, security agreements, etc.).

Summary of the Loan Agreement

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the Loan Agreement. This description is only a summary and does not purport to be complete and definitive. Reference is made to the Loan Agreement for the detailed provisions thereof.

General

The Loan Agreement initially commenced as of its initial date and is amended and restated as of September 1, 2008 and will end on the earliest to occur of October 1, 2034, or the date on which all of the Bonds shall have been fully paid or provision has been made for such payment pursuant to the Indenture. See "Summary of the Indenture — Discharge of Indenture."

The Company has agreed to repay the loan pursuant to the Loan Agreement by making timely payments to the Trustee in sufficient amounts to pay the principal of, premium, if any, and interest required to be paid on the Bonds on each date upon which any such payments are due. The Company has also agreed to pay (a) the agreed upon fees and expenses of the Trustee, the Bond Registrar, any Tender Agent and any Paying Agent appointed under the Indenture, (b) the expenses in connection with any redemption of the Bonds and (c) the reasonable expenses of the Issuer.

The Company covenants and agrees with the Issuer that it will cause the purchase of tendered Bonds that are not remarketed in accordance with the Indenture and, to that end, the Company shall cause funds to be made available to the Tender Agent at the times and in the manner required to effect such purchases in accordance with the Indenture; provided, however, that the obligation of the Company to make any such payment will be reduced by the amount of (A) moneys paid by the Remarketing Agent as proceeds of the remarketing of such Bonds by the Remarketing Agent, (B) moneys drawn under a Credit Facility, if any, for the purpose of paying such purchase price and (C) other moneys made available by the Company (see "Summary of the Bonds — Remarketing and Purchase of Bonds").

All payments to be made by the Company to the Issuer pursuant to the Loan Agreement (except the reasonable out-of-pocket expenses of the Issuer, the Trustee, the Paying Agent, the Bond Registrar, the Tender Agent and amounts related to indemnification) have been assigned by the Issuer to the Trustee, and the Company will pay such amounts directly to the Trustee. The obligations of the Company to make the payments pursuant to the Loan Agreement are absolute and unconditional.

Maintenance of Tax Exemption

The Company and the Issuer have agreed not to take any action that would result in the interest paid on the Bonds being included in gross income of any Bondholder (other than a holder who is a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) for federal income tax purposes or that adversely affects the validity of the Bonds.

Limitation on Liens

The Company has agreed that, so long as any of the Bonds are outstanding, it will not create, assume or guarantee debt for borrowed money secured by any mortgage, except as described above under "Security; Limitation on Liens."

Payment of Taxes

The Company has agreed to pay certain taxes and other governmental charges that may be lawfully assessed, levied or charged against or with respect to the Project (see, however, subparagraph (i) under "Summary of the Bonds — Redemptions — Extraordinary Optional Redemption in Whole"). The Company may contest such taxes or other governmental charges unless the security provided by the Indenture would be materially endangered.

Maintenance; Damage, Destruction and Condemnation

So long as any Bonds are outstanding, the Company will maintain the Project or cause the Project to be maintained in good working condition and will make or cause to be made all proper repairs, replacements and renewals necessary to continue to constitute the Project as solid waste disposal facilities under Section 142(a)(6) of the Code and the Act. However, the Company will have no obligation to maintain, repair, replace or renew any portion of the Project, the maintenance, repair, replacement or renewal of which becomes uneconomical to the Company because of certain events, including damage or destruction by a cause not within the Company's control, condemnation of the Project, change in government standards and regulations, economic or other obsolescence or termination of operation of generating facilities to the Project.

The Company, at its own expense, may remodel the Project or make substitutions, modifications and improvements to the Project as it deems desirable, which remodeling, substitutions, modifications and improvements will be deemed, under the terms of the Loan Agreement to be a part of the Project. The Company may not, however, change or alter the basic nature of the Project or cause it to lose its status under Section 142(a)(6) of the Code and the Act.

If, prior to the payment of all Bonds outstanding, the Project or any portion thereof is destroyed, damaged or taken by the exercise of the power of eminent domain and the Issuer or the Company receives net proceeds from insurance or a condemnation award in connection therewith, the Company must (i) cause such net proceeds to be used to repair or restore the Project or (ii) reimburse the Credit Facility Issuer for drawings under the Credit Facility for the redemption of the Bonds in whole or in part at their principal amount, which, by the opinion of Bond Counsel, will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes. See "Summary of the Bonds — Redemptions — Extraordinary Optional Redemption in Whole or in Part."

Project Insurance

The Company will insure the Project in a manner consistent with general industry practice.

Assignment, Merger and Release of Obligations of the Company

The Company may assign the Loan Agreement, pursuant to an opinion of Bond Counsel that such assignment will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, without obtaining the consent of either the Issuer or the Trustee. Such assignment, however, shall not relieve the Company from primary liability for any of its obligations under the Loan Agreement and performance and observance of the other covenants and agreements to be performed by the Company. The Company may dispose of all or substantially all of its assets or consolidate with or merge into another corporation, provided the acquirer of the Company's assets or the corporation with which it shall consolidate with or merge into shall be a corporation or other business organization organized and existing under the laws of the United States of America or one of the states of the United States of America or the District of Columbia, shall be qualified and admitted to do business in the Commonwealth of Kentucky and shall assume in writing all of the obligations and covenants of the Company under the Loan Agreement.

Release and Indemnification Covenant

The Company will indemnify and hold the Issuer harmless against any expense or liability incurred, including attorneys' fees, resulting from any loss or damage to property or any injury to or death of any person occurring on or about or resulting from any defect in the Project or from any action commenced in connection with the financing thereof.

Events of Default

Each of the following events constitutes an "event of default" under the Loan Agreement:

(1) failure by the Company to pay the amounts required for payment of the principal of, including purchase price for tendered Bonds and redemption and acceleration prices, and interest accrued, on the Bonds, at the times specified therein taking into account any periods of grace provided in the Indenture and the Bonds for the applicable payment of interest on the Bonds (see "Summary of the Indenture — Defaults and Remedies");

(2) failure by the Company to observe and perform any covenant, condition or agreement, other than as referred to in paragraph (1) above, for a period of thirty days after written notice by the Issuer or Trustee, provided, however, that if such failure is capable of being corrected, but cannot be corrected in such 30-day period, it will not constitute an event of default under the Loan Agreement if corrective action with respect thereto is instituted within such period and is being diligently pursued; or

(3) certain events of bankruptcy, dissolution, liquidation, reorganization or insolvency of the Company.

Under the Loan Agreement, certain of the Company's obligations (other than the Company's obligation (i) not to permit any action which would result in interest paid on the Bonds being included in gross income for federal and Kentucky income taxes and (ii) to make loan payments and certain other payments under the provisions of the Loan Agreement) may be suspended if by reason of force majeure (as defined in the Loan Agreement) the Company is unable to carry out such obligations.

Remedies

Upon the happening of an event of default under the Loan Agreement, the Issuer may, among other things, take whatever action at law or in equity may appear necessary or desirable to collect the amounts then due and thereafter to become due, or to enforce performance and observance of any obligation, agreement or covenant of the Company, under the Loan Agreement.

Any amounts collected upon the happening of any such event of default shall be applied in accordance with the Indenture or, if the Bonds have been fully paid (or provision for payment thereof has been made in accordance with the Indenture), made available to the Company.

Options to Prepay, Obligation to Prepay

The Company may prepay the loan pursuant to the Loan Agreement, in whole or in part, on certain dates, at the prepayment prices as shown under the captions “Summary of the Bonds — Redemptions — Optional Redemption,” “— Extraordinary Optional Redemption in Whole” and “— Extraordinary Optional Redemption in Whole or in Part.” Upon the occurrence of the event described under the caption “Summary of the Bonds — Redemptions — Mandatory Redemption; Determination of Taxability,” the Company shall be obligated to prepay the loan in an aggregate amount sufficient to redeem the required principal amount of the Bonds.

In each instance, the loan prepayment price shall be a sum sufficient, together with other funds deposited with the Trustee and available for such purpose, to redeem the requisite amount of the Bonds at a price equal to the applicable redemption price plus accrued interest to the redemption date, and to pay all reasonable and necessary fees and expenses of the Trustee, the Paying Agent and all other liabilities of the Company under the Loan Agreement accrued to the redemption date.

Amendments and Modifications

No amendment or modification of the Loan Agreement is permissible without the written consent of the Trustee. The Issuer and the Trustee may, however, without the consent of or notice to any Bondholders, enter into any amendment or modification of the Loan Agreement (i) which may be required by the provisions of the Loan Agreement or the Indenture, (ii) for the purpose of curing any ambiguity or formal defect or omission, (iii) in connection with any modification or change necessary to conform the Loan Agreement with changes and modifications in the Indenture or (iv) in connection with any other change which, in the judgment of the Trustee, does not adversely affect the Trustee or the Bondholders. Except for such amendments, the Loan Agreement may be amended or modified only with the consent of the Bondholders holding a majority in principal amount of the Bonds then outstanding (see “Summary of the Indenture — Supplemental Indentures” for an explanation of the procedures necessary for Bondholder consent); provided, however, that the approval of the Bondholders holding 100% in principal amount of the Bonds then outstanding is necessary to effectuate an amendment or modification with respect to the Loan Agreement of the type described in clauses

(i) through (iv) of the first sentence of the second paragraph of "Summary of the Indenture — Supplemental Indentures." Any amendments, changes or modification of the Loan Agreement that require the consent of the Bondholders must additionally be approved by the Credit Facility Issuer, if the Bonds are at the time secured by a Credit Facility. Additionally, so long as a Credit Facility is in place or while any amounts are outstanding under a Reimbursement Agreement, the Credit Facility Issuer must consent in writing to any amendment, change, or modification to the Agreement.

Summary of the Indenture

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the Indenture. This description is only a summary and does not purport to be complete and definitive. Reference is made to the Indenture for the detailed provisions thereof.

Security

Pursuant to the Indenture, the Issuer has assigned and pledged to the Trustee its interest in and to the Loan Agreement, including payments and other amounts due the Issuer thereunder, together with all moneys, property and securities from time to time held by the Trustee under the Indenture (with certain exceptions, including moneys held in or earnings on the Rebate Fund and the Purchase Fund). The Bonds are not directly secured by the Project.

No Pecuniary Liability of the Issuer

No provision, covenant or agreement contained in the Indenture or in the Loan Agreement, nor any breach thereof, shall give rise to any pecuniary liability of the Issuer or any charge upon its general credit or taxing powers. The Issuer has not obligated itself by making the covenants, agreements or provisions contained in the Indenture or in the Loan Agreement, except with respect to the Project and the application of the amounts assigned to payment of the principal of, premium, if any, and interest on the Bonds.

The Bond Fund

The payments to be made by the Company pursuant to the Loan Agreement to the Issuer and certain other amounts specified in the Indenture will be deposited into a Bond Fund established pursuant to the Indenture (the "Bond Fund") and will be maintained in trust by the Trustee. Moneys in the Bond Fund will be used for the payment of the principal of, premium, if any, and interest on the Bonds, and for the redemption of Bonds prior to maturity in the following order of priority: (i) proceeds of the Credit Facility, if any, deposited into the Bond Fund in accordance with the Indenture and (ii) any other moneys provided by or on behalf of the Company. Any moneys held in the Bond Fund will be invested by the Trustee at the specific written direction of the Company in certain Governmental Obligations, investment-grade corporate obligations and other investments permitted under the Indenture.

So long as a Credit Facility is then held by the Trustee and there is no default in the payment of principal or redemption price of or interest on the Bonds, any amounts in the Bond Fund provided by or on behalf of the Company will be paid to the Credit Facility Issuer to the extent of any amounts that the Company owes the Credit Facility Issuer pursuant to the Reimbursement Agreement. Any amounts remaining in the Bond Fund (first, from the proceeds of the Credit Facility, and second, from the moneys provided by or on behalf of the Company) after payment in full of the principal or redemption price of and interest on the Bonds (or provision for payment thereof) and payment of any outstanding fees and expenses of the Trustee (including its reasonable attorney fees and expenses) will be paid, first, to the Credit Facility Issuer, to the extent of any amounts that the Company owes the Credit Facility Issuer pursuant to the Reimbursement Agreement and, second, to the Company. Any amounts remaining in the Bond Fund (i) after all of the outstanding Bonds have been paid and discharged, (ii) after payment of all fees, charges and expenses to the Issuer, the Trustee, the Registrar and the Paying Agent and of all other amounts required to be paid under the Indenture and the Loan Agreement and (iii) after the receipt by the Trustee of the written request of the Company for such payment, will be paid to the Credit Facility Issuer, if any, to the extent of any amounts that the Company owes to such Credit Facility Issuer pursuant to the Reimbursement Agreement, and then to the Company to the extent that those moneys are in excess of the amounts necessary to effect the payment and discharge of the outstanding Bonds.

The Rebate Fund

A Rebate Fund has been created by the Indenture (the "Rebate Fund") and is maintained as a separate fund free and clear of the lien of the Indenture. The Issuer, the Trustee and the Company have agreed to comply with all rebate requirements of the Code and, in particular, the Company has agreed that if necessary, it will deposit in the Rebate Fund any such amount as is required under the Code. However, the Issuer, the Trustee and the Company may disregard the Rebate Fund provisions to the extent that they receive an opinion of Bond Counsel that such failure to comply will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes.

Discharge of Indenture

When all the Bonds and all fees and charges accrued and to accrue of the Trustee and the Paying Agent have been paid or provided for, and when proper notice has been given to the Bondholders or the Trustee that the proper amounts have been so paid or provided for, and if the Issuer is not in default in any other respect under the Indenture, the Indenture shall become null and void. The Bonds will be deemed to have been paid and discharged when there have been irrevocably deposited with the Trustee moneys sufficient to pay the principal, premium, if any, and accrued interest on such Bonds to the due date (whether such date be by reason of maturity or upon redemption) or, in lieu thereof, Governmental Obligations have been deposited which mature in such amounts and at such times as will provide the funds necessary to so pay such Bonds, and when all reasonable and necessary fees and expenses of the Trustee, the Authenticating Agent, the Bond Registrar and the Paying Agent have been paid or provided for.

Notwithstanding anything to the contrary, if any Bonds are rated by a rating service, no such Bonds will be deemed to have been paid and discharged by reason of any deposit pursuant to the Indenture, unless each such rating service has confirmed in writing to the Trustee that its rating will not be withdrawn or lowered as a result of any such deposit.

So long as the Company owes any amounts to the Credit Facility Issuer, if any, pursuant to the Reimbursement Agreement: (A) the lien of the Indenture may not be discharged; (B) such Credit Facility Issuer shall be subrogated to the extent of such amounts owed by the Company to such Credit Facility Issuer to all rights of the Bondholders to enforce the payment of the Bonds from the revenues and all other rights of the Bondholders under the Bonds, the Indenture and the Loan Agreement; (C) the Bondholders will be deemed paid to the extent of money drawn by the Trustee under the Credit Facility; and (D) subject to the Indenture, the Trustee will sign, execute and deliver all documents or instruments and do all things that may be reasonably required by the Credit Facility Issuer to effect the Credit Facility Issuer's subrogation of rights of enforcement and remedies set forth in the Indenture.

Defaults and Remedies

Each of the following events constitutes an "Event of Default" under the Indenture:

(a) failure to make payment of any installment of interest on any Bond within a period of one Business Day from the due date;

(b) failure to make punctual payment of the principal of, or premium, if any, on any Bond on the due date, whether at the stated maturity thereof, or upon proceedings for redemption, or upon the maturity thereof by declaration or if payment of the purchase price of any Bond required to be purchased pursuant to the Indenture is not made when such payment has become due and payable;

(c) failure of the Issuer to perform or observe any other of the covenants, agreements or conditions in the Indenture or in the Bonds which failure continues for a period of 30 days after written notice by the Trustee, provided, however, that if such failure is capable of being cured, but cannot be cured in such 30-day period, it will not constitute an event of default under the Indenture if corrective action in respect of such failure is instituted within such 30-day period and is being diligently pursued;

(d) the occurrence of an "event of default" under the Loan Agreement (see "Summary of the Loan Agreement — Events of Default");

(e) written notice from the Credit Facility Issuer to the Trustee of an event of default under the Reimbursement Agreement, by reason of which the Trustee has been directed to accelerate the Bonds; or

(f) if a Credit Facility is then held by the Trustee, on or before the close of business on the tenth calendar day following the honoring of a drawing under such Credit Facility to pay interest on the Bonds on an Interest Payment Date, written notice from the Credit Facility Issuer to the Trustee that the interest component of the Credit Facility will not be reinstated.

Upon the occurrence of an Event of Default under clauses (a), (b), (e) or (f) above, the Trustee must: (i) declare the principal of all Bonds and interest accrued thereon to be immediately due and payable; (ii) declare all payments under the Loan Agreement to be immediately due and payable and enforce each and every other right granted to the Issuer under the Loan Agreement for the benefit of the Bondholders; and (iii) if a Credit Facility securing the Bonds is in effect, make an immediate drawing under the Credit Facility in accordance with its terms and deposit the proceeds of such drawing in the Bond Fund pending application to the payment of principal of the Bonds, subject to the provisions of the Indenture reserving to the Credit Facility Issuer the right to direct default proceedings and providing for termination of default proceedings upon certain occurrences.

Interest on the Bonds will cease to accrue on the date of issuance of the declaration of acceleration of payment of principal and interest on the Bonds.

In exercising such rights, the Trustee will take any action that, in the judgment of the Trustee, would best serve the interests of the registered owners. Upon the occurrence of an Event of Default under the Indenture, the Trustee may also proceed to pursue any available remedy by suit at law or in equity to enforce the payment of the principal of, premium, if any, and interest on the Bonds then outstanding.

If the Trustee recovers any moneys following an Event of Default, unless the principal of the Bonds shall have been declared due and payable, all such moneys shall be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent, (ii) to the payment of all interest then due on the Bonds and (iii) to the payment of unpaid principal and premium, if any, of the Bonds. If the principal of the Bonds has become due or has been accelerated, such moneys shall be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and (ii) to the payment of principal of and interest then due and unpaid on the Bonds. In each case, however, Trustee and Paying Agent fees or costs will not be payable from moneys derived from Credit Facility drawings, any remarketing proceeds or moneys constituting certain Available Moneys under the Indenture.

No Bondholder may institute any suit or proceeding in equity or at law for the enforcement of the Indenture unless an Event of Default has occurred of which the Trustee has been notified or is deemed to have notice, and registered owners holding not less than 25% in aggregate principal amount of Bonds then outstanding shall have made written request to the Trustee to proceed to exercise the powers granted under the Indenture or to institute such action in their own name and the Trustee shall fail or refuse to exercise its powers within a reasonable time after receipt of indemnity satisfactory to it.

Any judgment against the Issuer pursuant to the exercise of rights under the Indenture shall be enforceable only against specific assigned payments, funds and accounts under the Indenture in the hands of the Trustee. No deficiency judgment shall be authorized against the general credit of the Issuer.

No default under paragraph (c) above shall constitute an Event of Default until actual notice is given to the Issuer and the Company by the Trustee, or to the Issuer, the Company and the Trustee by the registered owners holding not less than 25% in aggregate principal amount of all Bonds outstanding or the Issuer and the Company shall have had thirty days after such notice to correct the default and failed to do so. If the default is such that it cannot be corrected within the applicable period but is capable of being cured, it will not constitute an Event of Default if corrective action is instituted within the applicable period.

Notwithstanding the foregoing, in addition to the rights of the Trustee and the Bondholders to direct proceedings as described above, if a Credit Facility is in effect, for so long as such Credit Facility is outstanding and the Credit Facility Issuer is not in default in its duties under the Indenture or the Credit Facility, the Credit Facility Issuer issuing will have the absolute right to direct all proceedings on behalf of the Bondholders of the Bonds. Additionally, if the Event of Default which has occurred is an Event of Default under paragraphs (e) or (f) above, the Credit Facility Issuer, if any, will have no right to direct the Trustee or the Bondholders with respect to any matters, including remedies, and the holders of a majority in aggregate principal amount of the Bonds then outstanding, will have the right, at any time, by an instrument or instruments in writing executed and delivered to the Trustee, to direct the time, method and place of conducting all proceedings to be taken in connection with the enforcement of the terms and conditions of the Indenture, or for the appointment of a receiver or any other proceedings hereunder; provided, that such direction shall not be otherwise than in accordance with the provisions of law and of the Indenture.

If an Event of Default has occurred under the Indenture due to failure by the Credit Facility Issuer, if any, to honor a properly presented and conforming drawing by the Trustee under the Credit Facility then in effect in accordance with the terms thereof, all obligations of the Trustee to the Credit Facility Issuer and all rights of such Credit Facility Issuer under the Indenture will be suspended until the earlier of the cure of such failure or all of the Bonds have been paid in full.

Waiver of Events of Default

Except as provided below, the Trustee may in its discretion waive any Event of Default under the Indenture and shall do so upon the written request of the registered owners holding a majority in principal amount of all Bonds then outstanding. If, after the principal of all Bonds then outstanding shall have been declared to be due and payable and prior to any judgment or decree for the appointment of a receiver or for the payment of the moneys due shall have been entered, (i) the Company has caused to be deposited with the Trustee a sum sufficient to pay all matured installments of interest upon all Bonds and the principal of and premium, if any, on any and all Bonds which shall have become due otherwise than by reason of such declaration and the expenses of the Trustee in connection with such default (with interest thereon as provided in the Indenture) and (ii) all Events of Default under the Indenture (other than nonpayment of the principal of Bonds due by said declaration) shall have been remedied, then such Event of Default shall be deemed waived and such declaration and its consequences rescinded and annulled by the Trustee. Such waiver, rescission and annulment shall be binding upon all Bondholders. No such waiver, rescission and annulment shall extend to or affect any subsequent Event of Default or impair any right or remedy consequent thereon.

The Trustee may not waive any default under clauses (e) or (f) above unless the Trustee has received in writing from the Credit Facility Issuer a written notice of full reinstatement of the full amount of the Credit Facility and a written rescission of the notice of the Event of Default.

Notwithstanding the foregoing, nothing in the Indenture shall affect the right of a registered owner to enforce the payment of principal of, premium, if any, and interest on the Bonds after the maturity thereof.

Supplemental Indentures

The Issuer and the Trustee may enter into indentures supplemental to the Indenture without the consent of or notice to, the Bondholders in order (i) to cure any ambiguity or formal defect or omission in the Indenture, (ii) to grant to the Trustee, as may lawfully be granted, additional rights for the benefit of the Bondholders, (iii) to subject to the Indenture additional revenues, properties or collateral, (iv) to permit qualification of the Indenture under any federal statute or state blue sky law, (v) to add additional covenants and agreements of the Issuer for the protection of the Bondholders or to surrender or limit any rights reserved to the Issuer, (vi) to make any modification or change to the Indenture which, in the sole judgment of the Trustee, does not adversely affect the Trustee or any Bondholder, (vii) to make amendments to provisions relating to federal income tax matters under the Code or other relevant provisions if, in the opinion of Bond Counsel, those amendments would not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, (viii) to make any modifications or changes to the Indenture necessary to provide the securing of a Credit Facility or Alternate Credit Facility or any liquidity or credit support of any kind for the security of the Bonds (including without limitation any line of credit, letter of credit, guaranty agreement or insurance coverage), including any modifications of the Indenture or the Agreement necessary to upgrade or maintain the then applicable ratings on the Bonds; or (ix) to permit the issuance of the Bonds in other than book-entry-only form or to provide changes to or for the book-entry system.

Subject to the consent of the Credit Facility Issuer, if any, exclusive of supplemental indentures for the purposes set forth in the preceding paragraph, the consent of registered owners holding a majority in principal amount of all Bonds then outstanding is required to approve any supplemental indenture, except no such supplemental indenture shall permit, without the consent of all of the registered owners of the Bonds then outstanding, (i) an extension of the maturity of the principal of or the interest on any Bond issued under the Indenture or a reduction in the principal amount of any Bond or the rate of interest or time of redemption or redemption premium thereon, (ii) a privilege or priority of any Bond or Bonds over any other Bond or Bonds, (iii) a reduction in the principal amount of the Bonds required for consent to such supplemental indenture or (iv) the deprivation of any registered owners of the lien of the Indenture.

If at any time the Issuer shall request the Trustee to enter into any supplemental indenture requiring the consent of the registered owners of the Bonds, the Trustee, upon being satisfactorily indemnified with respect to expenses, must notify all such registered owners. Such notice shall set forth the nature of the proposed supplemental indenture and shall state that copies thereof are on file at the principal office of the Trustee for inspection. If, within sixty days (or such longer period as shall be prescribed by the Issuer or the Company) following the mailing of such notice, the registered owners holding the requisite amount of the Bonds outstanding shall have consented to the execution thereof, no Bondholder shall have any right to object or question the execution thereof.

No supplemental indenture shall become effective unless the Company consents to the execution and delivery of such supplemental indenture. The Company shall be deemed to have consented to the execution and delivery of any supplemental indenture if the Trustee does not receive a notice of protest or objection signed by the Company on or before 4:30 p.m., local time in the city in which the principal office of the Trustee is located, on the fifteenth day after the mailing to the Company of a notice of the proposed changes and a copy of the proposed supplemental indenture.

Notwithstanding the foregoing, any Supplemental Indenture that requires the consent of the Bondholders that (i) is to become effective while a Credit Facility is in place or while any amounts are outstanding under any Reimbursement Agreement and (ii) adversely affects the Credit Facility Issuer will not become effective unless and until the Credit Facility Issuer consents in writing to the execution and delivery of such Supplemental Indenture.

Cancellation of Credit Facility; Delivery of Alternate Credit Facility

The Trustee will, at the written direction of the Company but subject to the conditions described in this paragraph and the receipt of an Opinion of Bond Counsel stating that the cancellation of such Credit Facility is authorized under the Indenture and under the Act and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, cancel any Credit Facility in accordance with the terms thereof which cancellation may be without substitution therefor or replacement thereof; provided, that any such cancellation will not become effective, surrender of such Credit Facility will not take place and that Credit Facility will not terminate, in any event, until (i) payment by the Credit Facility Issuer has been made for any and all drawings by the Trustee effected on or before such cancellation date (including, if applicable, any drawings for payment of the purchase price of Bonds to be purchased pursuant to the Indenture in connection with such cancellation) and (ii) if the Bonds are in an Long Term Rate Period, only if the then current Long Term Rate Period for the Bonds is ending on, or the Bonds are subject to optional redemption on, the Interest Payment Date immediately preceding the date of such cancellation. Upon written notice given by the Company to the Trustee at least 20 days (35 days if the Bonds are bearing interest at the Long Term Rate) prior to the date of cancellation of any Credit Facility of such cancellation and the effective date of such cancellation, the Trustee will surrender such Credit Facility to the Credit Facility Issuer by which it was issued on or promptly after the effective date of such cancellation in accordance with its terms; provided, that such notice will not be given in any event, if the purchase price of any Bonds to be purchased pursuant to the Indenture in connection with such cancellation includes any premium unless the Company has certified in such notice that the Trustee can draw under a Credit Facility (other than any Alternate Credit Facility being delivered in connection with such cancellation) on the purchase date related to such purchase of Bonds in an aggregate amount sufficient to pay the premium due upon such purchase of Bonds on such purchase date.

The Company may, at its option, provide for the delivery to the Trustee of an Alternate Credit Facility in replacement of any Credit Facility then in effect. At least 20 days (35 days if the Interest Rate on the Bonds is a Long Term Rate) prior to the date of delivery of an Alternate Credit Facility to the Trustee, the Company must give notice, which notice will also be given to the Remarketing Agent, of such replacement to the Trustee, together with an Opinion of Bond Counsel to the effect that the delivery of such Alternate Credit Facility to the Trustee is authorized under the Indenture and the Act and complies with the terms thereof and that the delivery of such Alternate Credit Facility will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. The Trustee will then accept such Alternate Credit Facility and surrender the previously held Credit Facility, if any, to the previous Credit Facility Issuer for cancellation promptly on or after the 5th day after the Alternate Credit Facility becomes effective; provided, however, that such Alternate Credit Facility must become effective on an Interest Payment Date and, if the Bonds are in a Long Term Rate Period, such Alternate Credit Facility may only become effective on either the last Interest Payment Date for such Long Term Rate Period or an Interest Payment Date on which the Bonds are subject to optional redemption. The notice given to the Trustee shall also be given to the Issuer, the then current Credit Facility Issuer, Moody's, if the Bonds are then rated by Moody's, and S&P, if the Bonds are then rated by S&P; provided that the notice will not be given if the purchase price of any Bonds to be purchased pursuant to the Indenture in connection with such cancellation includes any premium unless the Company has certified in such notice that the Trustee can draw under a Credit Facility then in effect on the purchase date related to such purchase of Bonds in an aggregate amount sufficient to pay the premium due upon such purchase of Bonds on such purchase date and until payment under the Credit Facility to be surrendered shall have been made for any and all drawings by the Trustee effected on or before the date of such surrender for cancellation (including, if applicable, any drawings for payment of the purchase price of Bonds to be purchased pursuant to the Indenture in connection with such cancellation).

Any Alternate Credit Facility delivered to the Trustee must be accompanied by an opinion of counsel to the issuer or provider of such Credit Facility stating that such Credit Facility is a legal, valid, binding and enforceable obligation of such issuer or obligor in accordance with its terms.

The Bonds will be subject to mandatory tender for purchase on the date of cancellation of a Credit Facility and on the date of the delivery of an Alternate Credit Facility. See "Summary of the Bonds — Mandatory Purchases of Bonds."

Enforceability of Remedies

The remedies available to the Trustee, the Issuer and the owners upon an event of default under the Loan Agreement or the Indenture are in many respects dependent upon judicial actions which are often subject to discretion and delay. Under existing constitutional and statutory law and judicial decisions, the remedies specified by the Loan Agreement or the Indenture may not be readily available or may be limited. The various legal opinions to be delivered concurrently with the delivery of the Bonds will be qualified as to the enforceability of the various legal instruments by limitations imposed by principles of equity, bankruptcy, reorganization, insolvency, moratorium or other similar laws affecting the rights of creditors generally.

Reoffering

Subject to the terms and conditions of the Remarketing and Bond Purchase Agreement (the "Remarketing Agreement"), between the Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Remarketing Agent, the Remarketing Agent has agreed to purchase and reoffer the Bonds delivered to the Paying Agent for purchase, at a price equal to 100% of the principal amount of the Bonds, plus accrued interest (if any), and in connection therewith will receive compensation in the amount of $125,000, plus reimbursement of certain expenses. Under the terms of the Remarketing Agreement, the Company has agreed to indemnify the Remarketing Agent against certain civil liabilities, including liabilities under federal securities laws.

In the ordinary course of their business, the Remarketing Agent and certain of its affiliates, have engaged, and may in the future engage, in investment banking or commercial banking transactions with the Company.

Tax Treatment

On October 20, 2004, the date of original issuance and delivery of the Bonds, Bond Counsel delivered its opinion stating that under existing law, including current statutes, regulations, administrative rulings and official interpretations, subject to the qualifications and exceptions set forth below, interest on the Bonds will be excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion will be expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person" as such terms are used in Section 147(a) of the Code. Interest on the Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. Bond Counsel further opined that, subject to the assumptions stated in the preceding sentence, (i) interest on the Bonds would be excluded from gross income of the owners thereof for Kentucky income tax purposes and (ii) the Bonds would be exempt from all ad valorem taxes in Kentucky. Such opinion has not been updated as of the date hereof and no continuing tax exemption opinion is expressed by Bond Counsel.

Bond Counsel also will deliver an opinion in connection with this reoffering to the effect that the delivery of the Letter of Credit (i) is authorized or permitted by Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act") and the Indenture and (ii) will not adversely affect the validity of the Bonds or any exclusion from gross income of interest on the Bonds for federal income tax purposes to which interest on the Bonds would otherwise be entitled.

The opinions of Bond Counsel as to the excludability of interest from gross income for federal income tax purposes were based upon and assumed the accuracy of certain representations of facts and circumstances, including with respect to the Project, which were within the knowledge of the Company and compliance by the Company with certain covenants and undertakings set forth in the proceedings authorizing the Bonds which are intended to assure that the Bonds are and will remain obligations the interest on which is not includable in gross income of the recipients thereof under the law in effect on the date of such opinion. Bond

Counsel did not independently verify the accuracy of the certifications and representations made by the Company and the Issuer. On the date of the opinion and subsequent to the original delivery of the Bonds on October 20, 2004, such representations of facts and circumstances must be accurate and such covenants and undertakings must continue to be complied with in order that interest on the Bonds be and remain excludable from gross income of the recipients thereof for federal income tax purposes under existing law. Bond Counsel expressed no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents other than with the approval of Bond Counsel is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability.

Bond Counsel further opined that the Code prescribed a number of qualifications and conditions for the interest on state and local government obligations to be and to remain excluded from gross income for federal income tax purposes, some of which, including provisions for potential payments by the Issuers to the federal government, require future or continued compliance after issuance of the Bonds in order for the interest to be and to continue to be so excluded from the date of issuance. Noncompliance with certain of these requirements by the Company or the Issuer with respect to the Bonds could cause the interest on the Bonds to be included in gross income for federal income tax purposes and to be subject to federal income taxation retroactively to the date of their issuance. The Company and the Issuer each covenanted to take all actions required of each to assure that the interest on the Bonds shall be and remain excluded from gross income for federal income tax purposes, and not to take any actions that would adversely affect that exclusion.

The opinion of Bond Counsel as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds was subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, Bond Counsel expressed no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Owners of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August

7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income tax credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of Section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income. Prospective purchasers of the Bonds should consult their own tax advisors regarding such matters and any other tax consequences of holding the Bonds.

From time to time, there are legislative proposals in Congress which, if enacted, could alter or amend one or more of the federal tax matters referred to above or could adversely affect the market value of the Bonds. It cannot be predicted whether or in what form any such proposal might be enacted or whether, if enacted, it would apply to obligations (such as the Bonds) issued prior to enactment.

The opinion of Bond Counsel relating to the reoffering of the Bonds in substantially the form in which it is expected to be delivered on the Reoffering Date, redated to the Reoffering Date, is attached as Appendix B-2.

Legal Matters

Certain legal matters in connection with the reoffering of the Bonds will be passed upon by Stoll Keenon Ogden PLLC, Louisville, Kentucky, Bond Counsel. Certain legal matters pertaining to the Company will be passed upon by Jones Day, Chicago, Illinois, and John R. McCall, Esq., Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer of the Company. Winston & Strawn LLP, Chicago, Illinois, will pass upon certain legal matters for the Remarketing Agent.

Continuing Disclosure

Because the Bonds are special and limited obligations of the Issuer, the Issuer is not an "obligated person" for purposes of Rule 15c2-12 (the "Rule") promulgated by the SEC under the Exchange Act, and does not have any continuing obligations thereunder. Accordingly, the Issuer will not provide any continuing disclosure information with respect to the Bonds or the Issuer.

In order to enable the Remarketing Agent to comply with the requirements of the Rule, the Company has covenanted in a continuing disclosure undertaking agreement delivered to the Trustee for the benefit of the holders of the Bonds (the "Continuing Disclosure Agreement") to provide certain continuing disclosure for the benefit of the holders of the Bonds. Under its Continuing Disclosure Agreement, the Company has covenanted to take the following actions:

(a) The Company will provide to each nationally recognized municipal securities information repository ("NRMSIR"), recognized by the SEC pursuant to the Rule, and the state information depository, if any, of the Commonwealth of Kentucky (a "SID" and, together with the NRMSIR, a "Repository") recognized by the SEC (1) annual financial information of the type set forth in Appendix A to this Reoffering Circular (including any information incorporated by reference therein) and (2) audited financial statements prepared in accordance with generally accepted accounting principles, in each case not later than 120 days after the end of the Company's fiscal year.

(b) The Company will file in a timely manner with each NRMSIR or the Municipal Securities Rulemaking Board, and with the SID, if any, notice of the occurrence of any of the following events (if applicable) with respect to the Bonds, if material: (i) principal and interest payment delinquencies; (ii) non-payment related defaults; (iii) any unscheduled draws on debt service reserves reflecting financial difficulties; (iv) unscheduled draws on credit enhancement facilities reflecting financial difficulties; (v) substitution of credit or liquidity providers, or their failure to perform; (vi) adverse tax opinions or events affecting the tax-exempt status of the Bonds; (vii) modifications to rights of the holders of the Bonds; (viii) the giving of notice of optional or unscheduled redemption of any Bonds; (ix) defeasance of the Bonds or any portion thereof; (x) release, substitution, or sale of property securing repayment of the Bonds; and (xi) rating changes with respect to the Bonds or the Company or any obligated person, within the meaning of the Rule.

(c) The Company will file in a timely manner with each Repository notice of a failure by the Company to file any of the notices or reports referred to in paragraphs (a) and (b) above by the due date.

The Company may amend its Continuing Disclosure Agreement (and the Trustee shall agree to any amendment so requested by the Company that does not change the duties of the Trustee thereunder) or waive any provision thereof, but only with a change in circumstances that arises from a change in legal requirements, change in law, or change in the nature or status of the Company with respect to the Bonds or the type of business conducted by the Company; provided that the undertaking, as amended or following such waiver, would have complied with the requirements of the Rule on the date of issuance of the Bonds, after taking into account any amendments to the Rule as well as any change in circumstances, and the amendment or waiver does not materially impair the interests of the holders of the Bonds to which such undertaking relates, in the opinion of the Trustee or counsel expert in federal securities laws acceptable to both the Company and the Trustee, or is approved by the Beneficial Owners of a majority in aggregate principal amount of the outstanding Bonds. The Company acknowledges that its undertakings pursuant to the Rule described under this heading are intended to be for the benefit for the holders of the Bonds and shall be enforceable by the holders of those Bonds or by the Trustee on behalf of such holders. Any breach by the Company of these undertakings pursuant to the Rule will not constitute an event of default under the Indenture, the Loan Agreement or the Bonds.

This Reoffering Circular has been duly approved, executed and delivered by the Company.

KENTUCKY UTILITIES COMPANY

By: /s/ Daniel K. Arbough
Daniel K. Arbough
Treasurer

Appendix A

[DELETED AND REPLACED – SEE APPENDIX A TO SUPPLEMENT DATED MAY 2, 2011]

APPENDIX B

Opinion of Bond Counsel and Form of Reoffering Opinion of Bond Counsel

APPENDIX B-1

Opinion of Bond Counsel dated October 20, 2004 relating to the Bonds

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October 20, 2004

Re: $50,000,000 County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2004 Series A (Kentucky Utilities Company Project)

We hereby certify that we have examined certified copies of the proceedings of record of the County of Carroll, Kentucky (the "County"), acting by and through its Fiscal Court as its duly authorized governing body, preliminary to and in connection with the issuance by the County of its Environmental Facilities Revenue Bonds, 2004 Series A (Kentucky Utilities Company Project), dated their date of issuance, in the aggregate principal amount of $50,000,000 (the "Bonds"). The Bonds are issued under the provisions of Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act"), for the purpose of providing funds which will be used, with other funds provided by Kentucky Utilities Company (the "Company") for the current refunding of $50,000,000 aggregate principal amount of the County's Collateralized Solid Waste Disposal Facilities Revenue Bonds (Kentucky Utilities Company Project) 1993 Series A, dated December 1, 1993 (the "Prior Bonds"), which were issued for the purpose of financing the costs of construction, acquisition, installation and equipping of certain solid waste disposal facilities to serve the Ghent Generating Station of the Company in Carroll County, Kentucky (the "Project") in order to provide for the collection, storage, treatment, processing and final disposal of solid wastes, as provided by the Act.

The Bonds mature on October 1, 2034 and bear interest initially at the Dutch Auction Rate, as defined in the Indenture, hereinafter described, subject to change as provided in such Indenture. The Bonds will be subject to optional and mandatory redemption prior to maturity at the times, in the manner and upon the terms set forth in each of the Bonds. From such examination of the proceedings of the Fiscal Court of the County referred to above and from an examination of the Act, we are of the opinion that the County is duly authorized and empowered to issue the Bonds under the laws of the Commonwealth of Kentucky now in force.

We have examined an executed counterpart of a certain Loan Agreement, dated as of October 1, 2004 (the "Loan Agreement"), between the County and the Company and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Loan Agreement, pursuant to which the County has agreed to issue the Bonds and to lend the proceeds thereof to the Company to provide funds to pay and discharge, with other funds provided by the Company, the Prior Bonds. The Company has agreed to make Loan payments to the Trustee at times and in amounts fully adequate to pay maturing principal of, interest on and redemption premium, if any, on the Bonds as same become due and payable. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Loan Agreement; that the Loan Agreement has been duly authorized, executed and delivered by the County; and that the Loan Agreement is a legal, valid and binding obligation of the County, enforceable in accordance with its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

We have also examined an executed counterpart of a certain Indenture of Trust, dated as of October 1, 2004 (the "Indenture"), by and between the County and Wachovia Bank of Delaware, National Association, as trustee (the "Trustee"), securing the Bonds and setting forth the covenants and undertakings of the County in connection with the Bonds and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Indenture. Pursuant to the Indenture, certain of the County's rights under the Loan Agreement, including the right to receive payments thereunder, and all moneys and securities held by the Trustee in accordance with the Indenture (except moneys and securities in the Rebate Fund created thereby) have been assigned to the Trustee, as security for the holders of the Bonds. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Indenture; that the Indenture has been duly authorized, executed and delivered by the County; and that the Indenture is a legal, valid and binding obligation upon the parties thereto according to its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

In our opinion the Bonds have been validly authorized, executed and issued in accordance with the laws of the Commonwealths of Kentucky and Virginia now in full force and effect, and constitute legal, valid and binding special obligations of the County entitled to the benefit of the security provided by the Indenture and enforceable in accordance with their terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought. The Bonds are payable by the County solely and only from payments and other amounts derived from the Loan Agreement and as provided in the Indenture.

In our opinion, under existing laws, including current statutes, regulations, administrative rulings and official interpretations by the Internal Revenue Service, subject to the exceptions and qualifications contained in the succeeding paragraphs, interest on the Bonds is excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion is expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person," as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on the Bonds is a separate item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. In arriving at this opinion, we have relied upon representations, factual statements and certifications of the Company with respect to certain material facts which are solely within the Company's knowledge in reaching our conclusion, inter alia, that not less than 95% of the net proceeds of the Prior Bonds were used to finance solid waste disposal facilities qualified for financing under Section 142(a)(6) of the Code and the Act. Further, in arriving at the opinion set forth in this paragraph as to the exclusion from gross income of interest on the Bonds, we have assumed and this opinion is conditioned on, the accuracy of and continuing compliance by the Company and the County with representations and covenants set forth in the Loan Agreement and the Indenture which are intended to assure compliance with certain tax-exempt interest provisions of the Code. Such representations and covenants must be accurate and must be complied with subsequent to the issuance of the Bonds in order that interest on the Bonds be excluded from gross income for federal income tax purposes. Failure to comply with certain of such representations and covenants in respect of the Bonds subsequent to the issuance of the Bonds could cause the interest thereon to be included in gross income for federal income tax purposes retroactively to the date of issuance of the Bonds. We express no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents (other than with approval of this firm) is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability. We are further of the opinion that interest on the Bonds is excluded from gross income of the recipients thereof for Kentucky income tax purposes and that the Bonds are exempt from ad valorem taxation by the Commonwealth of Kentucky and all political subdivisions thereof.

Our opinion as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds is further subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, we express no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Holders of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that, for taxable years beginning after December 31, 1986, property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income.

We have received opinions of John R. McCall, Esq., General Counsel of the Company and Jones Day, Chicago, Illinois, counsel to the Company, of even date herewith. In rendering this opinion, we have relied upon said opinions with respect to the matters therein. We have also received an opinion of even date herewith of Hon. James C. Monk, County Attorney of the County, and relied upon said opinion with respect to the matters therein. Said opinions are in forms satisfactory to us as to both scope and content.

We express no opinion as to the title to, the description of, or the existence or priority of any liens, charges or encumbrances on, the Project.

In rendering the foregoing opinions, we are passing upon only those matters specifically set forth in such opinions and are not passing upon the investment quality of the Bonds or the accuracy or completeness of any statements made in connection with any sale thereof. The opinions herein are expressed as of the date hereof and we assume no obligation to supplement or update such opinions to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We are members of the Bar of the Commonwealth of Kentucky and do not purport to be experts on the laws of any jurisdiction other than the Commonwealth of Kentucky and the United States of America, and we express no opinion as to the laws of any jurisdiction other than those specified.

HARPER, FERGUSON & DAVIS
(Division of Ogden Newell & Welch PLLC)

By [signature]
SPENCER E. HARPER, JR.

APPENDIX B-2

(Form of Reoffering Opinion of Bond Counsel)

December 17, 2008

County of Carroll, Kentucky
Carrollton, Kentucky 41008

U.S. Bank National Association,
as successor Trustee
Nashville, Tennessee 37219

Re: Reoffering of $50,000,000 "County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2004 Series A (Kentucky Utilities Company Project)"

Ladies and Gentlemen:

This opinion is being furnished in accordance with the requirements of the Indenture of Trust, dated as of October 1, 2004 (the "Indenture"), between the County of Carroll, Kentucky (the "Issuer") and U.S. Bank National Association, a national banking association, as successor Trustee (the "Trustee"), pertaining to $50,000,000 principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2004 Series A (Kentucky Utilities Company Project), dated October 20, 2004 (the "Bonds"), in order to satisfy certain requirements of the Indenture. Pursuant to the authority of the Indenture and an ordinance adopted by the Issuer, the Company is terminating a municipal bond new issue insurance policy insuring the Bonds and simultaneously delivering a letter of credit to the Trustee for the benefit of the Bondholders. The terms used herein denoted by initial capitals and not otherwise defined shall have the meanings specified in the Indenture.

We have examined the law and such documents and matters as we have deemed necessary to provide this opinion. As to questions of fact material to the opinions expressed herein, we have relied upon the provisions of the Indenture and related documents, and upon representations made to us without undertaking to verify the same by independent investigation.

Based upon the foregoing, as of the date hereof, we are of the opinion that the delivery of a letter of credit and the reoffering of the Bonds as described herein (a) is authorized or permitted by the Act and the Indenture and (b) will not adversely affect the validity of the Bonds or any exclusion from gross income for federal income tax purposes to which interest on the Bonds would otherwise be entitled. Interest on the Bonds is not and will not be excluded from gross income during any period when the Bonds are held by the Company or a "related person" of the Company as defined in Section 147(a) of the Internal Revenue Code of 1986, as amended.

In rendering this opinion, we assume, without verifying, that the Issuer and the Company have complied and will comply with all covenants contained in the Indenture, the Loan Agreement between the Issuer and the Company, dated October 1, 2004, and other documents relating to the Bonds. We rendered our approving opinion at the time of the issuance of the Bonds relating to, among other things, the validity of the Bonds and the exclusion from federal income taxation of interest on the Bonds. We have not been requested to update or continue such opinion and have not undertaken to do so. Accordingly, we do not express any opinion with respect to the Bonds except as set forth above.

Our opinion represents our legal judgment based upon our review of the law and the facts that we deem relevant to render such opinion and is not a guarantee of a result. This opinion is given as of the date hereof and we assume no obligation to review or supplement this opinion to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We express no opinion herein as to the investment quality of the Bonds or the adequacy, accuracy or completeness of any information furnished to any person in connection with any offer or sale of the Bonds.

Respectfully submitted,

STOLL KEENON OGDEN PLLC

Appendix C

[DELETED AND REPLACED – SEE APPENDIX C TO SUPPLEMENT DATED MAY 2, 2011]

Supplement, dated May 2, 2011 to Reoffering Circular dated December 10, 2008, as supplemented as of December 16, 2008, October 29, 2010 and December 1, 2010 (the "Reoffering Circular")

$12,900,000
County of Mercer, Kentucky
Solid Waste Disposal Facility Revenue Bonds, 2000 Series A
(Kentucky Utilities Company Project)

Effective as of May 2, 2011, through April 22, 2014 (the Letter of Credit (as defined below) expiration date, subject to extension or earlier termination), payment of the principal of and interest on the above-referenced bonds (the "Bonds") when due will be paid with funds drawn under an irrevocable transferable direct pay letter of credit (the "Letter of Credit") issued by

SUMITOMO MITSUI BANKING CORPORATION, NEW YORK BRANCH

The Letter of Credit will permit the Trustee to draw with respect to the Bonds up to an amount sufficient to pay (i) the principal thereof (or that portion of the purchase price corresponding to principal) plus (ii) interest thereon (or that portion of the purchase price corresponding to interest) up to a maximum rate of 10% per annum for at least 45 days.

The Bonds will continue to bear interest at a Weekly Rate, determined by the Remarketing Agent, Morgan Stanley & Co. Incorporated, in accordance with the Indenture, payable on the first Business Day of each calendar month, commencing on June 1, 2011. The interest rate period, interest rate and Interest Rate Mode will be subject to change under certain conditions, as described in the Reoffering Circular. The Bonds are subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption following a determination of taxability prior to maturity, as described in the Reoffering Circular. The Bonds are subject to mandatory purchase on any date on which the Bonds are converted to a different Interest Rate Mode and upon the expiration of the Letter of Credit or any Alternate Credit Facility.

This supplement contains a description of the Letter of Credit and Sumitomo Mitsui Banking Corporation, New York Branch, the issuer of the Letter of Credit. For purposes of the Reoffering Circular, the Letter of Credit is a "Credit Facility" and Sumitomo Mitsui Banking Corporation, New York Branch is a "Credit Facility Issuer." Except as otherwise specified herein, information in the Reoffering Circular referred to above has not been amended or modified and the information contained herein is qualified by reference to, and should be read in conjunction with, the Reoffering Circular, including information incorporated therein by reference. Terms not otherwise defined herein shall have the meanings ascribed to them in such Reoffering Circular.

The eighth paragraph under the section of the Reoffering Circular captioned "Introductory Statement" is hereby amended to read in its entirety as follows:

Effective May 2, 2011, the Company will cause to be delivered an irrevocable transferable direct pay letter of credit (the "Letter of Credit"), issued by Sumitomo Mitsui Banking Corporation, New York Branch (the "Bank"), to provide for the timely payment of principal of and accrued interest (calculated for at least 45 days at the maximum rate of 10% per annum) on, and purchase price of, the Bonds. The Company will be required to reimburse the Bank for all amounts drawn by the Trustee under the Letter of Credit pursuant to the terms of a certain Reimbursement Agreement, to be dated as of May 2, 2011 (the "Reimbursement Agreement"), between the Company and the Bank. The Letter of Credit will expire on April 22, 2014, unless extended or earlier terminated.

* * * *

The section of the Reoffering Circular captioned "The Letter of Credit" is hereby amended to read in its entirety as follows:

THE LETTER OF CREDIT

The following summarizes certain provisions of the Letter of Credit and the Reimbursement Agreement, to which reference is made for the detailed provisions thereof. Unless otherwise defined in this Reoffering Circular, capitalized terms in the following summary are used as defined in the Letter of Credit and the Reimbursement Agreement. The Company is permitted under the Indenture to deliver an Alternate Credit Facility to replace the Letter of Credit. Any such Alternate Credit Facility must meet certain requirements described in the Indenture.

The Letter of Credit

The Letter of Credit will be an irrevocable transferable direct pay letter of credit issued by the Bank in order to provide additional security for the payment of principal of, purchase

price of, interest on and premium, if applicable, on any date when payments under the Bonds are due, including principal and interest payments and payments upon tender, redemption, acceleration or maturity of the Bonds. The Letter of Credit will provide for direct payments to or upon the order of the Trustee as set forth in the Letter of Credit in amounts sufficient to pay such amounts in accordance with the terms thereof.

The Letter of Credit will be issued in an amount equal to the aggregate principal amount of the outstanding Bonds, plus an amount that represents interest accrued thereon at an assumed maximum rate of 10% per annum for 45 days (the "Credit Amount"). The Trustee, upon compliance with the terms of the Letter of Credit, is authorized to draw up to (a) an amount sufficient (i) to pay principal of the Bonds, when due, whether at maturity or upon redemption or acceleration, and (ii) to pay the portion of the purchase price of the Bonds delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed (a "Liquidity Drawing") equal to the principal amount of the Bonds, plus (b) an amount not to exceed 45 days of accrued interest on the Bonds at an assumed rate of 10% per annum (i) to pay interest on the Bonds, when due, and (ii) to pay the portion of the interest accrued on the Bonds as of any Liquidity Drawing.

The amount available under the Letter of Credit will be automatically reduced by the amount of any drawing thereunder, subject to reinstatement as described below. With respect to a drawing by the Trustee solely to pay interest on the Bonds on an Interest Payment Date, the amount available under the Letter of Credit will be automatically reinstated in the amount of such drawing effective on the earlier of (i) receipt by the Bank from the Company of reimbursement of any drawing solely to pay interest in full or (ii) at the opening of business on the eleventh calendar day after the date the Bank honors such drawing, unless the Trustee has received written notice from the Bank by the tenth calendar day after the date the Bank honors such drawing that the Bank is not so reinstating the available amount due to the Company's failure to reimburse the Bank for such drawing in full, or that an event of default has occurred and is continuing under the $198,309,583.05 Letter of Credit Agreement dated as of April 29, 2011 among the Company, the lenders from time to time thereto, and Banco Bilbao Vizcaya Argentaria, S.A., New York Branch, as Administrative Agent (the "Credit Agreement") and, in either case, directing an acceleration of the Bonds pursuant to the Indenture. With respect to a Liquidity Drawing under the Letter of Credit, the amount available under the Letter of Credit will be automatically reduced by the principal amount of the Bonds purchased with the proceeds of such drawing plus the amount of accrued interest on such Bonds. In the event of the remarketing of the Bonds purchased with the proceeds of a Liquidity Drawing, the amount available under the Letter of Credit will be automatically reinstated upon receipt by the Bank or the Trustee on the Bank's behalf of an amount equal to such principal amount plus accrued interest.

The Letter of Credit will terminate on the earliest to occur of:

(i) the Bank's close of business on April 22, 2014 (such date, as extended from time to time in accordance with the Letter of Credit is defined as the "Stated Expiration Date");

(ii) the Bank's close of business on the date which is five Business Days following the date of receipt by the Bank of a certificate from the Trustee certifying that (a) no Bonds remain Outstanding within the meaning of the Indenture, (b) all drawings required to be made under the Indenture and available under the Letter of Credit have been made and honored, (c) an Alternate Credit Facility has been delivered to the Trustee in accordance with the Indenture to replace the Letter of Credit or (d) all of the outstanding Bonds were converted to Bonds bearing interest at a rate other than the Daily Rate or the Weekly Rate;

(iii) the Bank's close of business on the date of receipt by the Bank of a certificate from the Trustee confirming that the Trustee is required to terminate the Letter of Credit in accordance with the terms of the Indenture;

(iv) the date on which the Bank receives and honors an acceleration drawing certificate; or

(v) the Bank's close of business on the date which is 30 days after receipt by the Trustee of written notice from the Bank of an Event of Default under the Credit Agreement and instructing the Trustee to draw under the Letter of Credit.

Pursuant to the Credit Agreement, the Company is obligated to reimburse the Bank for all amounts drawn under the Letter of Credit, and to pay interest on all such amounts. The Company has also agreed to pay the Bank and the Administrative Agent fees for issuing and maintaining the Letter of Credit.

The Reimbursement Agreement

The Reimbursement Agreement, through incorporation of the terms of the Credit Agreement, imposes various covenants and agreements, including various financial and operating covenants, on the Company. Such covenants include, but are not limited to, covenants relating to (i) inspection of the books and financial records of the Company; (ii) mergers or consolidations; (iii) disposition of assets and (iv) capitalization ratios. Any such covenants may be amended, waived or modified at any time by the Bank and without the consent of the Trustee or the holders of the Bonds. Under certain circumstances, the failure of the Company to comply with such covenants may result in a mandatory tender or acceleration of the Bonds.

An Event of Default under the Credit Agreement will constitute an Event of Default under the Reimbursement Agreement. The following events will constitute an Event of Default under the Credit Agreement:

(i) the Company shall fail to pay when due any principal on any Reimbursement Obligations; or

(ii) the Company shall fail to pay when due any interest on the Reimbursement Obligations, any fee or any other amount payable under the Credit Agreement or under any other Loan Document for five (5) days following the date such payment becomes due thereunder; or

(iii) the Company shall fail to observe or perform certain covenants or agreements contained in the Credit Agreement, including those related to mergers, disposition of assets and capitalization ratios; or

(iv) the Company shall fail to give notice of a Default or Event of Default under the Credit Agreement within a specified number of days following knowledge of such occurrence; or

(v) the Company shall fail to observe or perform any covenant or agreement contained in the Credit Agreement or any other Loan Document (other than those covered above) for thirty (30) days after written notice thereof has been given to the defaulting party by the administrative agent, or at the request of the required lenders; or

(vi) any representation, warranty or certification made by the Company in the Credit Agreement or any other Loan Document or in any certificate, financial statement or other document delivered pursuant hereto or thereto shall prove to have been incorrect in any material respect when made or deemed made; or

(vii) the Company shall (i) fail to pay any principal or interest, regardless of amount, due in respect of any Material Debt beyond any period of grace provided with respect thereto, or (ii) fail to observe or perform any other term, covenant, condition or agreement contained in any agreement or instrument evidencing or governing any such Material Debt beyond any period of grace provided with respect thereto if the effect of any failure referred to in this clause (ii) is to cause, or to permit the holder or holders of such Material Debt or a trustee on its or their behalf to cause, such Material Debt to become due prior to its stated maturity; or

(viii) the Company shall commence a voluntary case or other proceeding seeking liquidation, reorganization or other relief with respect to itself or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any substantial part of its property, or shall consent to any such relief or to the appointment of or taking possession by any such official in an involuntary case or other proceeding commenced against it, or shall make a general assignment for the benefit of creditors, or shall fail generally to pay, or shall admit in writing its inability to pay, its debts as they become due, or shall take any corporate action to authorize any of the foregoing; or

(ix) an involuntary case or other proceeding shall be commenced against the Company seeking liquidation, reorganization or other relief with respect to it or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any substantial part of its property, and such involuntary case or other proceeding shall remain undismissed and unstayed for a period of 60 days; or an order for relief shall be entered against the Company under the Bankruptcy Code; or

(x) any member of the ERISA Group shall fail to pay when due an amount or amounts aggregating in excess of $50,000,000 which it shall have become liable to pay under Title IV of ERISA; or notice of intent to terminate a Material Plan shall be filed under Title IV of

ERISA by any member of the ERISA Group, any plan administrator or any combination of the foregoing; or the PBGC shall institute proceedings under Title IV of ERISA to terminate, to impose liability (other than for premiums under Section 4007 of ERISA) in respect of, or to cause a trustee to be appointed to administer any Material Plan; or a condition shall exist by reason of which the PBGC would be entitled to obtain a decree adjudicating that any Material Plan must be terminated; or there shall occur a complete or partial withdrawal from, or default, within the meaning of Section 4219(c)(5) of ERISA, with respect to, one or more Multiemployer Plans which could reasonably be expected to cause one or more members of the ERISA Group to incur a current payment obligation in excess of $50,000,000; or

(xi) the Company shall fail within sixty (60) days to pay, bond or otherwise discharge any judgment or order for the payment of money in excess of $20,000,000, entered against the Company that is not stayed on appeal or otherwise being appropriately contested in good faith; or

(xii) a Change of Control shall have occurred;

For purposes of the foregoing:

“Change of Control” means (i) the acquisition by any person, or two or more persons acting in concert, of beneficial ownership (within the meaning of Rule 13d-3 of the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended) of 25% or more of the outstanding shares of voting stock of PPL Corporation or its successors or (ii) the failure at any time of PPL Corporation or its successors to own 80% or more of the outstanding shares of the voting stock in the Company.

“Material Debt” means debt (other than debt under the Loan Documents) of the Company in a principal or face amount exceeding $50,000,000

Appendix C of the Reoffering Circular is hereby amended to read in its entirety as follows:

Sumitomo Mitsui Banking Corporation, New York Branch

The information under this heading has been provided solely by Sumitomo Mitsui Banking Corporation, New York Branch and is believed to be reliable. This information has not been verified independently by the Company, the Issuer or the Remarketing Agent. The Company, the Issuer and the Remarketing Agent make no representation whatsoever as to the accuracy, adequacy or completeness of such information.

Sumitomo Mitsui Banking Corporation

Sumitomo Mitsui Banking Corporation (*Kabushiki Kaisha Mitsui Sumitomo Ginko*) ("SMBC") is a joint stock corporation with limited liability (*Kabushiki Kaisha*) under the laws of Japan. The registered head office of SMBC is located at 1-2, Yurakucho 1-chome, Chiyoda-ku, Tokyo, Japan.

SMBC was established in April 2001 through the merger of two leading banks, The Sakura Bank, Limited and The Sumitomo Bank, Limited. In December 2002, Sumitomo Mitsui Financial Group, Inc. ("SMFG") was established through a stock transfer as a holding company under which SMBC became a wholly owned subsidiary. SMFG reported ¥ 123,159,513 million in consolidated total assets as of March 31, 2010.

SMBC is one of the world's leading commercial banks and provides an extensive range of banking services to its customers in Japan and overseas. In Japan, SMBC accepts deposits, makes loans and extends guarantees to corporations, individuals, governments and governmental entities. It also offers financing solutions such as syndicated lending, structured finance and project finance. SMBC also underwrites and deals in bonds issued by or under the guarantee of the Japanese government and local government authorities, and acts in various administrative and advisory capacities for certain types of corporate and government bonds. Internationally, SMBC operates through a network of branches, representative offices, subsidiaries and affiliates to provide many financing products including syndicated lending and project finance.

The New York Branch of SMBC is licensed by the State of New York Banking Department to conduct branch banking business at 277 Park Avenue, New York, New York, and is subject to examination by the State of New York Banking Department and the Federal Reserve Bank of New York.

Financial and Other Information

Audited consolidated financial statements for SMFG and its consolidated subsidiaries for the fiscal years ended March 31, 2010, as well as certain unaudited financial information for SMFG and SMBC for the fiscal period ended through December 31, 2010, as well as other corporate data, financial information and analyses are available in English on the website of the Parent at www.smfg.co.jp/english.

The information herein has been obtained from SMBC, which is solely responsible for its content. The delivery of the Reoffering Circular shall not create any implication that there has been no change in the affairs of SMBC since the date hereof, or that the information contained or referred herein is correct as of any time subsequent to its date.

Appendix A of the Reoffering Circular is hereby amended to read in its entirety as follows:

Appendix A

Kentucky Utilities Company –

Financial Statements and Additional Information

This Appendix A includes a description of the Business of Kentucky Utilities Company ("KU"), certain risk factors associated with KU, Selected Financial Information, Management's Discussion and Analysis, and the Consolidated Financial Statements as of December 31, 2010 and 2009 and for the Years Ended December 31, 2010, 2009, and 2008 (Audited).

The information contained in this Appendix A relates to and has been obtained from KU and from other sources as shown herein. The delivery of this Supplement shall not create any implication that there has been no change in the affairs of KU since the date hereof, or that the information contained or incorporated by reference in this Appendix A is correct at any time subsequent to its date. In this Appendix A, "KU", "the Company", "we", "us" or "our" refer to Kentucky Utilities Company.

Summary

Kentucky Utilities Company

Kentucky Utilities Company, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 514,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and to less than 10 customers in Tennessee. Our service area covers approximately 6,600 noncontiguous square miles. Approximately 98% of the electricity generated by us is produced by our coal-fired electric generating stations. The remainder is generated by natural gas and oil fueled combustion turbines and a hydroelectric power plant. In Virginia, we operate under the name Old Dominion Power Company. We also sell wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of LG&E and KU Energy LLC. On November 1, 2010, PPL Corporation purchased all of the interests of LG&E and KU Energy LLC and, indirectly, all of the stock of the Company from E.ON AG, making KU an indirect wholly-owned subsidiary of PPL Corporation. KU's affiliate, Louisville Gas and Electric Company ("LG&E"), is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and natural gas in Kentucky.

Kentucky Utilities Company

Financial Statements and Additional Information

As of December 31, 2010 and 2009 and

for the years ended December 31, 2010, 2009 and 2008

Index of Abbreviations

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Company	Kentucky Utilities Company
CT	Combustion Turbine
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Electric Energy, Inc.
EKPC	East Kentucky Power Cooperative, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC and Subsidiaries
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
Fidelia	Fidelia Corporation (an E.ON affiliate)
GAAP	U.S. Generally Accepted Accounting Principles
GAC	Group Annuity Contract
GHG	Greenhouse Gas
Gwh	Gigawatt hours or one thousand Mwh
IBEW	International Brotherhood of Electrical Workers
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
IRS	Internal Revenue Service
KCCS	Kentucky Consortium for Carbon Storage
KDAQ	Kentucky Division for Air Quality
Kentucky Commission	Kentucky Public Service Commission
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
kWh	Kilowatt hours
LG&E	Louisville Gas and Electric Company
LIBOR	London Interbank Offered Rate
LKE	LG&E and KU Energy LLC and Subsidiaries (formerly E.ON U.S. LLC and Subsidiaries)
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units

Index of Abbreviations

Moody's	Moody's Investor Services, Inc.
MVA	Megavolt-ampere
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NO_2	Nitrogen Dioxide
NOV	Notice of Violation
NOx	Nitrogen Oxide
OATT	Open Access Transmission Tariff
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation
PPL	PPL Corporation
Predecessor	The Company during the time period prior to November 1, 2010
PUHCA 2005	Public Utility Holding Company Act of 2005
RSG	Revenue Sufficiency Guarantee
S&P	Standard & Poor's Rating Service
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
Servco	LG&E and KU Services Company (formerly E.ON U.S. Services Inc.)
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool, Inc
Successor	The Company during the time period after October 31, 2010
TC1	Trimble County Unit 1
TC2	Trimble County Unit 2
TVA	Tennessee Valley Authority
Utilities	KU and LG&E
VDT	Value Delivery Team Process
Virginia Commission	Virginia State Corporation Commission

Table of Contents

Forward-Looking Information

KU uses forward-looking statements in this annual report. Statements that are not historical facts are forward-looking statements, and are based on beliefs and assumptions of management, and on information currently available to management. Forward-looking statements include statements preceded by, followed by or using such words as “believe,” “expect,” “anticipate,” “plan,” “estimate” or similar expressions. Such statements speak only as of the date they are made, and the Company undertakes no obligation to update publicly any of them in light of new information or future events. Actual results may materially differ from those implied by forward-looking statements due to known and unknown risks and uncertainties. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- fuel supply availability;
- weather conditions affecting generation production, customer energy use and operating costs;
- operation, availability and operating costs of existing generation facilities;
- transmission and distribution system conditions and operating costs;
- collective labor bargaining negotiations;
- the outcome of litigation against the Company;
- potential effects of threatened or actual terrorism or war or other hostilities;
- commitments and liabilities;
- market demand and prices for energy, capacity, transmission services, emission allowances and delivered fuel;
- competition in retail and wholesale power markets;
- liquidity of wholesale power markets;
- defaults by counterparties under the Company’s energy, fuel or other power product contracts;
- market prices of commodity inputs for ongoing capital expenditures;
- capital market conditions, including the availability of capital or credit, changes in interest rates, and decisions regarding capital structure;
- the fair value of debt and equity securities and the impact on defined benefit costs and resultant cash funding requirements for defined benefit plans;
- interest rates and their effect on pension and retiree medical liabilities;
- volatility in or the impact of other changes in financial or commodity markets and economic conditions;
- profitability and liquidity, including access to capital markets and credit facilities;
- new accounting requirements or new interpretations or applications of existing requirements;
- securities and credit ratings;
- current and future environmental conditions and requirements and the related costs of compliance, including environmental capital expenditures, emission allowance costs and other expenses;
- political, regulatory or economic conditions in states, regions or countries where the Company conducts business;
- receipt of necessary governmental permits, approvals and rate relief;
- new state or federal legislation, including new tax, environmental, health care or pension-related legislation;
- state or federal regulatory developments;
- the impact of any state or federal investigations applicable to the Company and the energy industry;
- the effect of any business or industry restructuring;
- development of new projects, markets and technologies;

- performance of new ventures; and
- asset acquisitions and dispositions.

In light of these risks and uncertainties, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than the Company has described. For additional details regarding these and other risks and uncertainties, see Risk Factors.

Business

General

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 514,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in five counties in southwestern Virginia and less than ten customers in Tennessee. KU's service area covers approximately 6,600 noncontiguous square miles. Approximately 98% of the electricity generated by KU is produced by its coal-fired electric generating stations. The remainder is generated by natural gas and oil fueled CTs and a hydroelectric power plant. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

On November 1, 2010, KU became an indirect wholly owned subsidiary of PPL, when PPL acquired all of the outstanding limited liability company interests in the Company's direct parent, LKE, from E.ON US Investments Corp. LKE, a Kentucky limited liability company, also owns the affiliate, LG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy and distribution and sale of natural gas in Kentucky. Following the acquisition, the Company's business has not changed. KU and LG&E are continuing as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies.

Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K.

Predecessor and Successor

KU's historical financial results are presented using "Predecessor" or "Successor" to designate the periods before or after PPL's acquisition of LKE. Predecessor covers the time period prior to November 1, 2010. Successor covers the time period after October 31, 2010. Certain accounting and presentation methods were changed to acceptable alternatives to conform to PPL accounting policies and the cost basis of certain assets and liabilities were changed as of November 1, 2010, as a result of the application of push-down accounting. Consequently, the financial position, results of operations and cash flows for the Successor period are not comparable to the Predecessor period.

Despite the separate presentation, the core operations of the Company have not changed. See Note 1, Summary of Significant Accounting Policies, for the major differences in Predecessor and Successor accounting policies. See Note 2, Acquisition by PPL, for information regarding the acquisition and the purchase accounting adjustments.

Operations

Dollars are in millions unless otherwise noted.

The sources of operating revenues and volumes of sales for the following periods in 2010, 2009 and 2008 were as follows:

	Successor		Predecessor					
	November 1, 2010 through December 31, 2010		January 1, 2010 through October 31, 2010		Year Ended December 31, 2009		Year Ended December 31, 2008	
	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)
Residential	$ 106	1,394	$ 440	5,788	$ 480	6,594	$ 462	6,803
Industrial and commercial	117	1,876	588	9,152	637	10,171	636	10,709
Municipals	15	326	88	1,676	91	1,848	92	1,971
Other retail	20	273	114	1,453	118	1,647	108	1,707
Wholesale	5	68	18	376	29	660	107	2,894
	$ 263	3,937	$ 1,248	18,445	$ 1,355	20,920	$ 1,405	24,084

KU's peak load in 2010 was 4,517 Mw on December 15, 2010, when the temperature dropped to a low of 3 degrees Fahrenheit in Lexington. KU's all time peak load was 4,640 Mw and occurred on January 16, 2009, when the temperature dropped to a low of -2 degrees Fahrenheit in Lexington.

The Company's power generating system includes coal-fired steam generating stations, with natural gas and oil fueled CTs which supplement the system during peak or emergency periods. As of December 31, 2010, KU's system capacity was:

Fuel/Plant	Total Summer Mw Capacity (a)	% Ownership	Ownership or Lease Interest in Mw	Location
Coal (steam)				
Ghent	1,918	100.00	1,918	Carroll County, KY
E.W. Brown	684	100.00	684	Mercer County, KY
Green River	163	100.00	163	Muhlenberg County, KY
Tyrone	71	100.00	71	Woodford County, KY
OVEC - Clifty Creek (b)	1,304	2.50	33	Jefferson County, IN
OVEC - Kyger Creek (b)	1,086	2.50	27	Gallia County, OH
Total steam	5,226		2,896	
Natural gas/oil (combustion turbines)				
E.W. Brown Units 8-11	480	100.00	480	Mercer County, KY
Trimble County Units 7-10 (c)	640	63.00	403	Trimble County, KY
Trimble County Units 5-6 (c)	320	71.00	227	Trimble County, KY
E.W. Brown Units 6-7 (c)	338	62.00	214	Mercer County, KY
Paddy's Run (c)	158	47.00	74	Jefferson County, KY
E.W. Brown Unit 5	129	47.00	63	Mercer County, KY
Haefling	36	100.00	36	Fayette County, KY
Total combustion turbines	2,101		1,497	

Fuel/Plant	Total Summer Mw Capacity (a)	% Ownership	Ownership or Lease Interest in Mw	Location
Hydro				
Dix Dam Hydroelectric Station	24	100.00	24	Mercer County, KY
Total hydro	24		24	
Total system capacity	7,351		4,417	

(a) The capacity of generation units is based on a number of factors, including the operating experience and physical conditions of the units and may be revised periodically to reflect changed circumstances.
(b) KU is contractually entitled to 2.50% of OVEC's output based on a power purchase agreement which is comprised of annual minimum debt service payments, as well as contractually-required reimbursement of plant operating, maintenance and other expenses. OVEC's capacity is shown at unit nameplate ratings.
(c) Units are jointly owned with LG&E. See Note 14, Jointly Owned Electric Utility Plant, for further information.

With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. Unit 2 is coal-fired and has a capacity of 760 Mw, of which KU's share is 462 Mw.

On December 31, 2010, KU's transmission system included 132 substations (54 of which are shared with the distribution system) with transformer capacity of approximately 13,136 MVA and approximately 4,076 miles of lines. The distribution system included 480 substations (54 of which are shared with the transmission system) with transformer capacity of approximately 7,044 MVA, and approximately 14,123 miles of overhead lines and 2,221 miles of underground conduit.

KU had a power supply contract with OMU that was terminated by OMU in May 2010. KU owns 20% of EEI's common stock and 2.5% of OVEC's common stock. KU has power purchase rights for its portion of OVEC's output. Additional information regarding this relationship is provided in Note 1, Summary of Significant Accounting Policies and Note 13, Commitments and Contingencies.

KU contracts with the TVA to act as KU's transmission reliability coordinator and SPP to function as KU's independent transmission operator, pursuant to FERC requirements. The TVA and SPP contracts provide services through August 31, 2011 and August 31, 2012, respectively. See Note 3, Rates and Regulatory Matters, for further information.

KU and LG&E jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has

excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are recorded as intercompany wholesale sales and purchases and are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the Utilities. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

Substantially all of KU's real and tangible property located in Kentucky is subject to a mortgage lien, securing its first mortgage bonds. See Note 11, Long-Term Debt, for further information.

Rates and Regulations

PPL, KU's ultimate parent, is a holding company under PUHCA 2005. PPL, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries are subject to extensive regulation by the FERC with respect to numerous matters, including: electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. KU believes that it has adequate authority (including financing authority) under existing FERC Orders and regulations to conduct its business and will seek additional authorization when necessary.

The Company is subject to the jurisdiction of the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority in virtually all matters related to electric utility regulation, and as such, its accounting is subject to the regulated operations guidance of the FASB ASC. Given its competitive position in the marketplace and the status of regulation in Kentucky, Virginia and Tennessee there are no plans or intentions to discontinue the application of the regulated operations guidance of the FASB ASC.

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments Corp., PPL and E.ON.

The transaction was subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including the FERC and state regulators in Kentucky, Virginia and Tennessee) and the absence of injunctions or restraints imposed by governmental entities.

Change of control and financing-related applications were filed on May 28, 2010, with the Kentucky Commission and on June 15, 2010, with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings and data request filings and responses occurred. Early termination of the Hart-Scott-Rodino waiting period was received on August 2, 2010.

A hearing in the Kentucky Commission proceedings was held on September 8, 2010, at which time a unanimous settlement agreement was presented. In the settlement, KU committed that no base rate increases would take effect before January 1, 2013. The KU rate increases that took effect on August 1,

2010, were not impacted by the settlement. Under the terms of the settlement, KU retains the right to seek approval for the deferral of "extraordinary and uncontrollable costs." Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and demand-side management cost trackers. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Company file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits KU to earn up to a 10.75% return on equity. Any earnings above a 10.75% return on equity will be shared with customers on a 50%/50% basis. On September 30, 2010, the Kentucky Commission issued an Order approving the transfer of ownership of KU via the acquisition of E.ON U.S. by PPL, incorporating the terms of the submitted settlement. On October 19, 2010 and October 21, 2010, respectively, Orders approving the acquisition of E.ON U.S. by PPL were received from the Virginia Commission and the Tennessee Regulatory Authority. The Commissions' Orders contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In mid-September 2010, KU and other applicants in the FERC change of control proceeding reached an agreement with the protesters, whereby such protests have been withdrawn. The agreement, which was filed for consideration with the FERC, includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an agreement not to terminate certain KU municipal customer contracts prior to January 2017, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that KU agreed not to seek the same transaction-related cost from retail customers and agreements to coordinate with protesters in certain open or ongoing matters. A FERC Order approving the transaction was received on October 26, 2010, and the transaction was completed on November 1, 2010.

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $135 million annually. In June 2010, KU and all of the intervenors, except the AG, agreed to a stipulation providing for an increase in electric base rates of $98 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulation, including a return on equity range of 9.75-10.75%. The new rates became effective on August 1, 2010.

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based on a return on equity of 12%. As permitted, pursuant to a Virginia Commission Order, KU elected to implement the proposed rates effective November 1, 2009, on an interim basis. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing a base rate revenue increase of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU refunded approximately $1 million in interim rate amounts in excess of the ultimate approved rates.

In January 2009, a significant ice storm passed through KU's service area causing approximately 199,000 customer outages, followed closely by a severe wind storm in February 2009 causing approximately 44,000 customer outages. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future

recovery approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $62 million based on its actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, the Company established a regulatory asset of $57 million for actual costs incurred. KU received approval in its 2010 base rate case to recover this asset over a ten year period with recovery beginning August 1, 2010.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service area causing significant outages and system damage. In October 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset and defer for future recovery approximately $3 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $3 million based on its actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, the Company established a regulatory asset of $2 million for actual costs incurred. The Company received approval in its 2010 base rate case to recover this asset over a ten year period beginning August 1, 2010.

In September 2008, KU filed an application with the FERC for increases in electric base rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from an all-in stated unit charge rates to an unbundled formula rate, including an annual adjustment mechanism. In May 2009, the FERC issued an Order approving a settlement among the parties in the case, incorporating increases of approximately 3% from prior rates and a return on equity of 11%. In May 2010, KU submitted to the FERC the proposed current annual adjustments to the formula rates, which incorporated certain proposed increases. Updated rates, including certain further adjustments from a review process involving wholesale requirements customers, became effective as of July 1, 2010.

By mutual agreement, the parties' settlement of the 2008 application left outstanding the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. An Order was issued by the FERC in July 2010, indicating that KU is not required to allocate a portion of any renewable resources to the twelve municipalities, thus resolving the remaining issue.

In July 2008, KU filed an application with the Kentucky Commission requesting an increase in electric base rates. In January 2009, KU, the AG, the KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which KU's electric base rates decreased by $9 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009.

For a further discussion of regulatory matters, see Note 3, Rates and Regulatory Matters.

<u>Coal Supply</u>

Coal-fired generating units provided approximately 98% of KU's net kWh generation for 2010. The remaining net generation was provided by natural gas and oil fueled CTs and a hydroelectric plant. Coal is expected to be the predominant fuel used by KU in the foreseeable future, with natural gas and oil

being used for peaking capacity and flame stabilization in coal-fired boilers or in emergencies. The Company has no nuclear generating units and has no plans to build any in the foreseeable future.

Fuel inventory is maintained at levels estimated to be necessary to avoid operational disruptions at the coal-fired generating units. Reliability of coal deliveries can be affected periodically by a number of factors including fluctuations in demand, coal mine production issues and other supplier or transporter operating difficulties.

KU has entered into coal supply agreements with various suppliers for coal deliveries for 2011 and beyond and normally augments its coal supply agreements with spot market purchases. The Company has a coal inventory policy which it believes provides adequate protection under most contingencies.

KU expects to continue purchasing most of its coal, which has sulfur content in the 0.7% - 3.5% range, from western and eastern Kentucky, West Virginia, southern Indiana, southern Illinois, Ohio and Wyoming for the foreseeable future. This supply, in combination with the installation of FGDs (SO_2 removal systems), KU expects its use of higher sulfur coal to increase, the combination of which is expected to enable KU to continue to provide electric service in compliance with existing environmental laws and regulations. Coal is delivered to KU's generating stations by a mix of transportation modes, including barge, truck and rail.

Seasonality

Demand for and market prices for electricity are affected by weather. As a result, KU's overall operating results in the future may fluctuate substantially on a seasonal basis, especially when more severe weather conditions such as heat waves or winter storms make such fluctuations more pronounced. The pattern of this fluctuation may change depending on the type and location of the facilities KU owns and the terms of its contracts to purchase or sell electricity.

Environmental Matters

General

Protection of the environment is a major priority for KU and a significant element of its business activities. KU's properties and operations are subject to extensive environmental-related oversight by federal, state and local regulatory agencies, including via air quality, water quality, waste management and similar laws and regulations. Therefore, KU must conduct its operations in accordance with numerous permit and other requirements issued under or contained in such laws or regulations.

Climate Change

Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3% by 2012, 17% by 2020 and 83% by 2050. Similar legislation has been considered in the U.S. Senate, but the prospects for

passage remain uncertain. In late 2009, the EPA issued a final endangerment finding relating to mobile sources of GHGs and a GHG reporting requirement beginning in 2010. In 2010, the EPA issued a final rule requiring implementation of best available control technology for GHG emissions from new or modified power plants, effective January 2011. In December 2010, the EPA announced that it intends to propose New Source Performance Standards addressing GHG emissions from new and existing power plants, with a proposed rule expected in July 2011. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, KU, as a primarily coal-fired utility, could be highly affected by such proceedings.

Among other emissions, GHGs include carbon-dioxide, which is produced via the combustion of fossil fuels such as coal and natural gas. KU's generating fleet is approximately 66% coal-fired, 34% oil/natural gas-fired and less than 1% hydroelectric based on capacity. During 2010, KU produced approximately 98% of its electricity from coal, 2% from natural gas combustion and less than 1% from hydroelectric generation, based on Mwh. During 2010, KU's emissions of GHGs were approximately 16.4 million metric tons of carbon-dioxide equivalents from KU's owned or controlled generation sources. While its generation activities account for the bulk of its GHG emissions, other GHG sources at KU include operation of motor vehicles and powered equipment, leakage or evaporation associated with natural gas pipelines, refrigerating equipment and similar activities.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. Based on prior regulatory precedent, KU currently anticipates that many of such direct costs may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, but the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change and other environmental matters will likely increase the level of capital expenditures and operating and maintenance costs incurred by the Company during the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. In order to comply with the coal combustion residual rules and the above referenced air rules, capital expenditures for KU are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary. This estimate does not include compliance with GHG rules or contemplated water-related environmental changes. See Risk Factors, Management's Discussion and Analysis and Note 13, Commitments and Contingencies, for further information.

State Executive or Legislative Matters

In November 2008, the Commonwealth of Kentucky issued an action plan to create efficient, sustainable energy solutions and strategies and move toward state energy independence. The plan outlines the following seven strategies to work toward these goals:

- Improve the energy efficiency of Kentucky's homes, buildings, industries and transportation fleet
- Increase Kentucky's use of renewable energy
- Sustainably grow Kentucky's production of biofuels
- Develop a coal-to-liquids industry in Kentucky to replace petroleum-based liquids
- Implement a major and comprehensive effort to increase natural gas supplies, including coal-to-natural gas in Kentucky
- Initiate aggressive carbon capture/sequestration projects for coal-generated electricity in Kentucky
- Examine the use of nuclear power for electricity generation in Kentucky

In December 2009, the Governor of Kentucky's Executive Task Force on Biomass and Biofuels issued a final report to establish potential strategic actions to develop biomass and biofuels industries in Kentucky. The plan noted the potential importance of biomass as a renewable energy source available to Kentucky and discussed various goals or mechanisms, such as the use of approximately 25 million tons of biomass for generation fuel annually, allotment of electricity and natural gas taxes and state tax credits to support biomass development.

In January 2010, a state-established Kentucky Climate Action Plan Council (the "Council") commenced formal activities. The Council, which includes governmental, industry, consumer and other representatives, seeks to identify possible Kentucky responses to potential climate change and federal legislation, including increasing statewide energy efficiency, energy independence and economic growth. The Council has established various technical work groups, including in the areas of energy supply and energy efficiency/conservation, to provide input, data and recommendations.

During the current session of the Kentucky General Assembly, as during prior legislative sessions, legislators have introduced or are expected to introduce various bills with respect to environmental or utility matters, including potential requirements relating to renewable energy portfolios, energy conservation measures, coal mining or coal byproduct operations and other matters. The current session is scheduled to end in March 2011 and until such time the prospects and final terms of any such legislation cannot be determined. Legislative and regulatory actions as a result of these proposals and their impact on KU, which may be significant, cannot currently be predicted.

Franchises and Licenses

KU provides electric delivery service in its various service areas pursuant to certain franchises, licenses, statutory service areas, easements and other rights or permissions granted by state legislatures, cities or municipalities or other entities.

Competition

There are currently no other electric utilities operating within the electric service areas of KU. Neither the Kentucky General Assembly nor the Kentucky Commission has adopted or approved a plan or timetable for retail electric industry competition in Kentucky. The nature or timing of any legislative or regulatory actions regarding industry restructuring and their impact on KU, which may be significant, cannot currently be predicted. Virginia, formerly a competitive jurisdiction, has enacted legislation which implements a hybrid model of cost-based regulation. See Note 3, Rates and Regulatory Matters, for further information.

Employees and Labor Relations

KU had 974 employees at December 31, 2010, consisting of 973 full-time employees and 1 part-time employee. Of the total employees, 145, or 15%, were operating, maintenance and construction employees represented by the IBEW Local 2100 and the United Steelworkers of America ("USWA") Local 9447-01. In August 2009, the Company and its employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement that provides for negotiated increases or changes to wages, benefits or other provisions and annual wage re-openers. In August 2008, the Company and its employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement that provides for negotiated increases or changes to wages, benefits or other provisions and annual wage re-openers.

Officers of the Company

Officers are elected annually by the Board of Directors. There are no family relationships among any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

Except as may be set forth in Legal Proceedings, there have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

Listed below are the executive officers at December 31, 2010.

Name	Age	Positions Held During the Past Five Years	Dates
Victor A. Staffieri	55	Chairman of the Board, President and Chief Executive Officer	May 2001 – present
John R. McCall	67	Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer	July 1994 – present
Chris Hermann	63	Senior Vice President – Energy Delivery	February 2003 – present
Paula H. Pottinger	53	Senior Vice President – Human Resources	January 2006 – present
S. Bradford Rives	52	Chief Financial Officer	September 2003 – present
Paul W. Thompson	53	Senior Vice President – Energy Services	June 2000 – present

Officers generally serve in the same capacities at the Company, LKE and LG&E.

Risk Factors

Any of the events or circumstances described as risks below could result in a significant or material adverse effect on the business, results of operations, cash flows or financial condition. The risks and uncertainties described below may not be the only risks and uncertainties that KU faces. Additional risks and uncertainties not currently known or that KU currently deems immaterial may also result in a significant or material adverse effect on the business, results of operations, cash flow or financial condition.

KU's business is subject to significant and complex governmental regulation.

Various federal and state entities, including but not limited to the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority, regulate many aspects of utility operations of KU, including the following:

- the rates that KU may charge and the terms and conditions of the Company's service and operations;
- financial and capital structure matters;
- siting and construction of facilities;
- mandatory reliability and safety standards and other standards of conduct;
- accounting, depreciation and cost allocation methodologies;
- tax matters;
- affiliate restrictions;
- acquisition and disposal of utility assets and securities; and
- various other matters.

Such regulations or changes thereto may subject KU to higher operating costs or increased capital expenditures and failure to comply could result in sanctions or possible penalties. In any rate-setting proceedings, federal or state agencies, intervenors and other permitted parties may challenge rate requests and ultimately reduce, alter or limit the rates the Company seeks.

The profitability of KU is highly dependent on its ability to recover the costs of providing energy and utility services to its customers and earn an adequate return on its capital investments. KU currently provides services to retail customers at rates approved by one or more federal or state regulatory commissions, including those commissions referred to above. While these rates are generally regulated based on an analysis of their costs incurred in a base year, the rates KU is allowed to charge may or may not match its costs at any given time. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commissions will consider all of the costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of KU's costs or an adequate return on KU's capital investments. If the Company's costs are not adequately recovered through rates, it could have an adverse affect on the business, results of operations, cash flows or financial condition.

As part of the PPL acquisition commitments, KU has agreed, subject to certain limited exceptions such as fuel and environmental cost recoveries, that no base rate increase would take effect for Kentucky retail customers before January 1, 2013.

Transmission and interstate market activities of KU, as well as other aspects of the business, are subject to significant FERC regulation.

KU is subject to extensive regulation by the FERC covering matters including rates charged to transmission users, market-based or cost-based rates applicable to wholesale customers; interstate power market structure; construction and operation of transmission facilities; mandatory reliability standards; standards of conduct and affiliate restrictions and other matters. Existing FERC regulation, changes thereto or issuances of new rules or situations of non-compliance, including but not limited to the areas of market-based tariff authority, RSG resettlements in the MISO market, mandatory reliability standards and natural gas transportation regulation can affect the earnings, operations or other activities of KU.

Changes in transmission and wholesale power market structures could increase costs or reduce revenues.

Wholesale sales fluctuate with regional demand, fuel prices and contracted capacity. Changes to transmission and wholesale power market structures and prices may occur in the future, are not estimable and may result in unforeseen effects on energy purchases and sales, transmission and related costs or revenues. These can include commercial or regulatory changes affecting power pools, exchanges or markets in which KU participates.

KU undertakes significant capital projects and these activities are subject to unforeseen costs, delays or failures, as well as risk of inadequate recovery of resulting costs.

KU's business is capital intensive and requires significant investments in energy generation and distribution and other infrastructure projects, such as projects for environmental compliance. The completion of these projects without delays or cost overruns is subject to risks in many areas, including the following:

- approval, licensing and permitting;
- land acquisition and the availability of suitable land;
- skilled labor or equipment shortages;
- construction problems or delays, including disputes with third party intervenors; increases in commodity prices or labor rates;
- contractor performance;
- environmental considerations and regulations;
- weather and geological issues; and
- political, labor and regulatory developments.

Failure to complete capital projects on schedule or on budget, or at all, could adversely affect the Company's financial performance, operations and future growth.

The costs of compliance with, and liabilities under, environmental laws are significant and are subject to continual changes.

Extensive federal, state and local environmental laws and regulations are applicable to KU's air emissions, water discharges and the management of hazardous and solid waste, among other areas; and

the costs of compliance or alleged non-compliance cannot be predicted with certainty but could be material. In addition, KU's costs may increase significantly if the requirements or scope of environmental laws or regulations, or similar rules, are expanded or changed from prior versions by the relevant agencies. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions. Many of these environmental law considerations are also applicable to the operations of key suppliers, or customers, such as coal producers, industrial power users, etc., and may impact the costs of their products or their demand for KU's services.

KU is subject to operational and financial risks regarding certain on-going developments concerning environmental regulation.

A number of regulatory initiatives have been implemented or are under development which could have the effect of significantly increasing the environmental regulation or operational or compliance costs related to a number of emissions or operating activities which are associated with the combustion of coal as occurs at the Company's generating stations. Such developments could include potential new or revised federal or state legislation or regulation regarding emissions of NOx, SO_2, mercury and other particulates generally and regarding storage of coal combustion byproducts. Additional regulatory initiatives may occur in other areas involving the Company's operations, including revision of limitations on water discharge or intake activities or increased standards relating to polychlorinated biphenyl usage. Compliance with any new laws or regulations in these matters could result in significant changes to KU's operations, significant capital expenditures by the Company or significant increases in the cost of conducting business.

Operating results are affected by weather conditions, including storms and seasonal temperature variations, as well as by significant man-made or accidental disturbances, including terrorism or natural disasters.

These weather or other factors can significantly affect the finances or operations of KU by changing demand levels; causing outages; damaging infrastructure or requiring significant repair costs; affecting capital markets and general economic conditions or impacting future growth.

KU is subject to operational and financial risks regarding potential developments concerning global climate change.

Various regulatory and industry initiatives have been implemented or are under development to regulate or otherwise reduce emissions of GHGs, which are emitted from the combustion of fossil fuels such as coal and natural gas, as occurs at the Company's generating stations. Such developments could include potential federal or state legislation or industry initiatives allocating or limiting GHG emissions; establishing costs or charges on GHG emissions or on fuels relating to such emissions; requiring GHG capture and sequestration; establishing renewable portfolio standards or generation fleet-diversification requirements to address GHG emissions; promoting energy efficiency and conservation; changes in transmission grid construction, operation or pricing to accommodate GHG-related initiatives; or other measures. The generation fleet of KU is predominantly coal-fired and may be highly impacted by developments in this area. Compliance with any new laws or regulations regarding the reduction of GHG emissions could result in significant changes to KU's operations, significant capital expenditures by the Company and a significant increase in the cost of conducting business. KU may face strong

competition for, or difficulty in obtaining, required GHG-compliance related goods and services, including construction services, emissions allowances and financing, insurance and other inputs relating thereto. Increases in KU's costs or prices of producing or selling electric power due to GHG-related developments could materially reduce or otherwise affect the demand, revenue or margin levels applicable to its power, thus adversely affecting its financial condition or results of operations.

KU is subject to physical, market and economic risks relating to potential effects of climate change.

Climate change may produce changes in weather or other environmental conditions, including temperature or precipitation changes, such as warming or drought. These changes may affect farm and agriculturally-dependent businesses and activities, which are an important part of Kentucky's economy, and thus may impact consumer demand for electric power. Temperature increases could result in increased overall electricity volumes or peaks and precipitation changes could result in altered availability of water for plant cooling operations. These or other meteorological changes could lead to increased operating costs, capital expenses or power purchase costs by KU. Conversely, climate change could have a number of potential impacts tending to reduce demand. Changes may entail more frequent or more intense storm activity, which, if severe, could temporarily disrupt regional economic conditions and adversely affect electricity demand levels. As discussed in other risk factors, storm outages and damage often directly decrease revenues or increase expenses, due to reduced usage and higher restoration charges, respectively. GHG regulation could increase the cost of electric power, particularly power generated by fossil fuels, and such increases could have a depressive effect on the regional economy. Reduced economic and consumer activity in the service area of KU, both in general and specific to certain industries and consumers accustomed to previously low-cost power, could reduce demand for KU's electricity. Also, demand for services could be similarly lowered should consumers' preferences or market factors move toward favoring energy efficiency, low-carbon power sources or reduced electric usage generally.

The business of KU is subject to risks associated with local, national and worldwide economic conditions.

The consequences of prolonged recessionary conditions may include a lower level of economic activity and uncertainty or volatility regarding energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption, unfavorable changes in energy and commodity prices and slower customer growth, which may adversely affect KU's future revenues and growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and the ability to raise capital. A deterioration of economic conditions may lead to decreased production by KU's industrial customers and, therefore, lower consumption of electricity. Decreased economic activity may also lead to fewer commercial and industrial customers and increased unemployment, which may in turn impact residential customers' ability to pay. Further, worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure. Changes in global demand may impact the ability to acquire sufficient supplies and the cost of those commodities may be higher than expected.

KU's business is concentrated in the Midwest United States, specifically Kentucky and Virginia.

Although the business of KU is concentrated in Kentucky and Virginia, it also operates in Tennessee. Local and regional economic conditions, such as population growth, industrial growth, expansion and economic development or employment levels, as well as the operational or financial performance of major industries or customers, can affect the demand for energy and KU's results of operations. Significant industries and activities in the service area of KU include aluminum and steel smelting and fabrication; chemical processing; coal, mineral and ceramic related activities; educational institutions; health care facilities; paper and pulp processing; metal fabrication; and water and sewer utilities. Any significant downturn in these industries or activities or in local and regional economic conditions in KU's service area may adversely affect the demand for electricity in the service area.

KU is subject to operational risks relating to KU's generating plants, transmission facilities, distribution equipment, information technology systems and other assets and activities.

Operation of power plants, transmission and distribution facilities, information technology systems and other assets and activities subjects KU to many risks, including the breakdown or failure of equipment; accidents; security breaches, viruses or outages affecting information technology systems; labor disputes; obsolescence; delivery/transportation problems and disruptions of fuel supply and performance below expected levels. Occurrences of these events may impact the ability of KU to conduct its business efficiently or lead to increased costs, expenses or losses.

Although KU maintains customary insurance coverage for certain of these risks common to utilities, it does not have insurance covering the transmission and distribution systems, other than substations, because it has found the cost of such insurance to be prohibitive. If KU is unable to recover the costs incurred in restoring transmission and distribution properties following damage resulting from ice storms, tornados or other natural disasters or to recover the costs of other liabilities arising from the risks of its business, through a change in rates or otherwise, or if such recovery is not received on a timely basis, it may not be able to restore losses or damages to its properties without an adverse effect on its financial condition, results of operations or its reputation.

KU is subject to liability risks relating to its generation, transmission, distribution and retail businesses.

The conduct of the physical and commercial operations of KU subjects it to many risks, including risks of potential physical injury, property damage or other financial affects, caused to or caused by employees, customers, contractors, vendors, contractual or financial counterparties and other third parties.

KU could be negatively affected by rising interest rates, downgrades to bond credit ratings or other negative developments in its ability to access capital markets.

In the ordinary course of business, KU is reliant upon adequate long-term and short-term financing means to fund significant capital expenditures, debt interest or maturities and operating needs. As a capital-intensive business, the Company is sensitive to developments in interest rate levels; credit rating considerations; insurance, security or collateral requirements; market liquidity and credit availability and

refinancing steps necessary or advisable to respond to credit market changes. Changes in these conditions could result in increased costs and decreased liquidity available to the Company.

KU is subject to commodity price risk, credit risk, counterparty risk and other risks associated with the energy business.

General market or pricing developments or failures by counterparties to perform their obligations relating to energy, fuels, other commodities, goods, services or payments could result in potential increased costs to the Company.

KU is subject to risks associated with defined benefit retirement plans, health care plans, wages and other employee-related matters.

KU sponsors pension and postretirement benefit plans for its employees. Risks with respect to these plans include adverse developments in legislation or regulation, future costs or funding levels, returns on investments, market fluctuations, interest rates and actuarial matters. Changes in health care rules, market practices or cost structures can affect current or future funding requirements or liabilities. Without sustained growth in respective investments over time to increase the value of plan assets, KU could be required to fund plans with significant amounts of cash. KU is also subject to risks related to changing wage levels, whether related to collective bargaining agreements or employment market conditions, ability to attract and retain key personnel and changing costs of providing health care benefits.

KU is subject to risks associated with federal and state tax regulations.

Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact results of operations. KU is required to make judgments in order to estimate its obligations to taxing authorities. These tax obligations include income, property, sales and use and employment-related taxes. KU also estimates its ability to utilize tax benefits and tax credits. Due to the revenue needs of the states and jurisdictions in which KU operates, various tax and fee increases may be proposed or considered. KU cannot predict whether legislation or regulation will be introduced or the effect on the Company of any such changes. If enacted, any changes could increase tax expense and could have a negative impact on its results of operations and cash flows.

Legal Proceedings

Rates and Regulatory Matters

For a discussion of current rates and regulatory matters, including recent electric base rate increase proceedings, rate commitments in change-of-control proceedings, TC2 proceedings, FERC, Kentucky Commission and Virginia Commission proceedings and other rates or regulatory matters affecting KU, see Note 3, Rates and Regulatory Matters, and Note 13, Commitments and Contingencies.

Environmental

For a discussion of environmental matters, including potential coal combustion byproduct or ash pond regulation; additional reductions in SO_2, NOx and other regulated emissions; NOVs and other emissions proceedings; environmental permit challenges; and other environmental items affecting KU, see Risk Factors, Note 3, Rates and Regulatory Matters, and Note 13, Commitments and Contingencies.

Climate Change

For a discussion of matters relating to potential climate change, GHG emission or global warming developments, including increased legislative and regulatory activity which could limit or increase costs applicable to fossil fuel generation sources, legal proceedings claiming damages relating to global warming, GHG reporting requirements and other matters, see Business, Risk Factors, Management's Discussion and Analysis and Note 13, Commitments and Contingencies.

Litigation

In connection with an administrative proceeding alleging a violation by a former Argentine affiliate under that country's 2002-2003 emergency currency exchange laws, claims are pending against the affiliate's then directors, including two individuals who are executive officers of the Company, in a specialized Argentine financial criminal court. Under applicable Argentine laws, directors of a local company may be liable for monetary penalties for a subject company's violations of the currency laws. The affiliate and the relevant executive officers believe their actions were in compliance with the relevant laws and have presented defenses in the administrative and criminal proceedings. LKE has standard indemnification arrangements with its executive officers. The former affiliate is now owned by a third party, which has agreed to indemnify LKE and the relevant executive officers.

For a discussion of litigation matters, see Note 13, Commitments and Contingencies.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against KU. To the extent that damages are assessed in any of these lawsuits, the Company believes that its insurance coverage is adequate. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits and claims will have a material adverse effect on KU's financial position or results of operations.

Selected Financial Data

Dollars are in millions unless otherwise noted.

	Successor	Predecessor				
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,			
			2009	2008	2007	2006
Operating revenues	$ 263	$ 1,248	$ 1,355	$ 1,405	$ 1,272	$ 1,210
Operating income	$ 65	$ 285	$ 269	$ 260	$ 267	$ 235
Net income	$ 35	$ 140	$ 133	$ 158	$ 167	$ 152
Total assets	$ 6,059	$ 5,145	$ 4,956	$ 4,518	$ 3,796	$ 3,148
Long-term debt obligations (including amounts due within one year)	$ 1,841	$ 1,682	$ 1,682	$ 1,532	$ 1,264	$ 843

Management's Discussion and Analysis and Notes to Financial Statements should be read in conjunction with the above information.

Management's Discussion and Analysis

Management's Discussion and Analysis should be read in conjunction with the Financial Statements and Notes for the years ended December 31, 2010, 2009 and 2008. Dollars are in millions unless otherwise noted.

The purpose of "Management's Discussion and Analysis" is to provide information about KU's performance in implementing its' strategies and managing risks and challenges. Specifically:

- "Overview" provides background regarding KU's business and identifies significant matters with which management is primarily concerned in evaluation of KU's financial condition and operating results.
- "Results of Operations" provides a description of KU's operating results in 2010, 2009 and 2008, including a review of earnings and a brief outlook for 2011.
- "Financial Condition" provides an analysis of KU's liquidity position and credit profile, including its sources of cash (including bank credit facilities and sources of operating cash flow) and uses of cash (including contractual obligations and capital expenditure requirements) and the key risks and uncertainties that impact KU's past and future liquidity position and financial condition. This subsection also includes a discussion of KU's current credit ratings.
- "Application of Critical Accounting Policies and Estimates" provides an overview of the accounting policies that are particularly important to the results of operations and financial condition of KU and that require its management to make significant estimates, assumptions and other judgments.

Overview

KU is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. See the Business section for a description of the business. The rates KU charges its customers requires approval of the appropriate regulatory government agency. See Note 3, Rates and Regulatory Matters, for information regarding rate cases, regulatory assets and liabilities and other regulatory matters.

KU and its affiliate, LG&E, are wholly owned subsidiaries of LKE, a Kentucky limited liability company. PPL acquired LKE on November 1, 2010. Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K. Following the acquisition, both KU and LG&E continue operating as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies. See Note 2, Acquisition by PPL, for further information regarding the acquisition.

In operating its business, the Company faces several risks including credit risks, liquidity risks, interest rate risks and commodity and price risks. For instance, the Company has credit risks from counterparties, customers and effects of its' own credit ratings. KU attempts to manage these risks through the adoption of financial and operational risk management programs that, among other things, are designed to monitor and reduce its' exposure to these risks. Identified within "Management's

Discussion and Analysis" of "Financial Condition" and "Results of Operations" are risks KU's management currently consider material; these risks are not the only risks faced by KU. Additional risks not presently known or currently deemed immaterial may also impair KU's business operations. See Risk Factors and Financial Condition - Risk Management for further discussion.

Predecessor and Successor Financial Presentation

KU's financial statements and related financial and operating data include the periods before or after PPL's acquisition of LKE on November 1, 2010, and are labeled as Predecessor or Successor. KU applied push-down accounting to account for the acquisition. For accounting purposes only, push-down accounting is considered to create a new entity due to new cost basis assigned to assets, liabilities and equity as of the acquisition date. Consequently, KU's results of operations and cash flows for the Predecessor and Successor periods in 2010 are shown separately, rather than combined, in its audited financial statements.

In the "Management's Discussion and Analysis" of "Results of Operations" and "Financial Condition", the Company has included disclosure of the combined Predecessor and Successor results of operations and cash flows. Such presentation is considered to be a non-GAAP disclosure. KU has included such disclosure because the Company believes it facilitates the comparison of 2010 operating and financial performance to 2009 and 2008, and because the core operations of the Company have not changed as a result of the acquisition.

Competition

See the Business section for information concerning competition.

Environmental Matters

General

Protection of the environment is a major priority for KU and a significant element of its business activities. Extensive federal, state and local environmental laws and regulations are applicable to KU's air emissions, water discharges and the management of hazardous and solid waste, among other areas; and the costs of compliance or alleged non-compliance cannot be predicted with certainty but could be material. In addition, costs may increase significantly if the requirements or scope of environmental laws or regulations, or similar rules, are expanded or changed from prior versions by the relevant agencies. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions. Many of these environmental law considerations are also applicable to the operations of key suppliers, or customers, such as coal producers, industrial power users, etc., and may impact the costs of their products or their demand for KU's services.

Climate Change

Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of

Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3% by 2012, 17% by 2020 and 83% by 2050. Similar legislation has been considered in the U.S. Senate, but the prospects for passage remain uncertain. In late 2009, the EPA issued a final endangerment finding relating to mobile sources of GHGs and a GHG reporting requirement beginning in 2010. In 2010, the EPA issued a final rule requiring implementation of best available control technology for GHG emissions from new or modified power plants, effective January 2011. In December 2010, the EPA announced that it intends to propose New Source Performance Standards addressing GHG emissions from new and existing power plants, with a proposed rule expected in July 2011. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, KU, primarily a coal-fired utility, could be highly affected by such proceedings.

Other Environmental Regulatory Initiatives

The EPA has proposed or announced that it intends to propose a number of additional environmental regulations that could substantially impact utilities with coal-fired generating assets. These regulatory initiatives include revisions to the ambient air quality standards for SO_2, NO_2, ozone and particulate matter 2.5 microns in size or less, rules aimed at mitigating the interstate transport of SO_2 and NOx, a program governing emissions of hazardous air pollutants from utility generating units, a program for the management of coal combustion residuals, revised effluent guidelines for utility generating facilities and standards for cooling water intake structures. Such requirements could potentially mandate upgrade of existing emission controls, installation of additional emission controls such as FGDs, SCRs, fabric filter bag houses, activated carbon injection, wet electrostatic precipitators, closure of ash ponds and retrofit of landfills, installation of cooling towers, deployment of new water treatment technologies and retirement of facilities that cannot be retrofitted on a cost effective basis.

The cost to KU and the effect on KU’s business of complying with potential GHG restrictions and other environmental regulatory initiatives will depend upon provisions of any final rules and how the rules are implemented by the EPA. Some of the design elements which may have the greatest effect on KU include (a) the required levels and timing of emissions caps, discharge limits or similar standards, (b) the sources covered by such requirements, (c) transition and mitigation provisions, such as phase-in periods, free allowances or price caps, (d) the availability and pricing of relevant mitigation or control technologies, goods or services and (e) economic, market and customer reaction to electricity price and demand changes due to environmental concerns.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. Based on prior regulatory precedent, KU currently anticipates that many of such direct costs may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, but the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change and other environmental matters will likely increase the level of

capital expenditures and operating and maintenance costs incurred by the Company during the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. In order to comply with the coal combustion residual rules and the above referenced air rules, capital expenditures for KU are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary. This estimate does not include compliance with GHG rules or contemplated water-related environmental changes. See Risk Factors and Note 13, Commitments and Contingencies, for further information.

Results of Operations

The utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year. Revenue and earnings are generally highest during the first and third quarters, and lowest in the second quarter, due to weather.

Net Income

The following table summarizes the significant components of net income for 2010, 2009 and 2008 and the changes therein:

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Total operating revenues	$ 1,511	$ 263	$ 1,248	$1,355	$ 1,405
Total operating expenses	1,161	198	963	1,086	1,145
Operating income	350	65	285	269	260
Equity in earnings of unconsolidated venture	3	-	3	1	30
Interest expense	14	8	6	6	14
Interest expense to affiliated companies	64	2	62	69	58
Other income (expense) – net	(2)	-	(2)	5	8
Income before income taxes	273	55	218	200	226
Income tax expense	98	20	78	67	68
Net income	$ 175	$ 35	$ 140	$ 133	$ 158

The change in KU's net income was as follows:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Total operating revenues	$ 156	$ (50)
Total operating expenses	75	(59)
Operating income	81	9
Equity in earnings of unconsolidated venture	2	(29)
Interest expense	8	(8)
Interest expense to affiliated companies	(5)	11
Other income (expense) – net	(7)	(3)
Income (loss) before income taxes	73	(26)
Income taxes	31	(1)
Net income	$ 42	$ (25)

Operating Revenues

The $156 million increase from 2009 to 2010 and $50 million decrease from 2008 to 2009 in operating revenues were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Retail sales volumes (a)	$ 73	$ (43)
Base rate price variance (b)	39	(5)
Demand revenue (c)	16	(1)
Sales to municipal customers (d)	12	(1)
Increased recoverable capital spending billed through the ECR	8	50
Other operating revenue primarily due to late payment charges	6	6
FAC price variance (e)	5	(2)
Merger surcredit termination in February 2009	2	13
Transmission sales	1	-
Increased recoverable program spending billed through the DSM	1	9
Wholesale sales (f)	(7)	(77)
VDT surcredit termination in August 2008	-	1
	$ 156	$ (50)

(a) Retail sales volumes increased during 2010 compared to 2009 as a result of increased consumption primarily due to increased heating degree days during the first and fourth quarters of 2010 and increased cooling degree days during the second and third quarters of 2010. Additionally, improved economic conditions in 2010 and significant storm outages in 2009 contributed to the increased volumes.

The decrease in retail sales volumes during 2009 compared to 2008 was attributable to reduced consumption by retail customers, as a result of milder weather and weakened economic conditions, in addition to significant storm outages during 2009.

(b) The increase in revenues due to the base rate price variance during 2010 compared to 2009 resulted from higher base rates effective August 1, 2010. See Note 3, Rates and Regulatory Matters, for further discussion of the 2010 Kentucky rate case.

The decrease in revenues due to the base rate price variance during 2009 compared to 2008 resulted from a reduction in base energy rates effective February 6, 2009. See Note 3, Rates and Regulatory Matters, for further discussion of the 2008 Kentucky rate case.

(c) Demand revenues increased during 2010 compared to 2009 as a result of higher demand rates effective August 1, 2010 and higher customer peak demand. See Note 3, Rates and Regulatory Matters, for further discussion of the 2010 Kentucky rate case.

(d) The increase in sales to municipal customers during 2010 compared to 2009 was primarily due to increased volumes as a result of increased cooling and heating degree days, improved economic conditions and a decline in storm outages.

(e) FAC revenues increased during 2010 compared to 2009 as a result of increased recoverable fuel costs billed to customers through the FAC due to higher fuel prices.

The decrease in the FAC revenue during 2009 compared to 2008 resulted from lower fuel costs billed to customers through the FAC ($2 million) due to a refund of power purchased costs from OMU ($6 million) partially offset by increased recoverable fuel costs ($4 million) billed to retail customers through the FAC.

(f) The decrease in wholesale sales during 2010 compared to 2009 was primarily due to increased consumption by industrial customers, as a result of improved economic conditions, increased consumption by residential customers, as a result of increased cooling and heating degree days and an increase in LG&E’s coal-fired generation outages in the first six months of 2010. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between KU and LG&E.

The decrease in wholesale sales during 2009 compared to 2008 was primarily due to lower sales volumes to LG&E and third-parties due to lower economic capacity, caused by low spot market pricing and higher scheduled coal-fired generation outages. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between KU and LG&E.

Operating Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority. Operating expenses and the changes therein for 2010, 2009 and 2008 follow:

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Fuel for electric generation	$ 495	$ 78	$ 417	$ 434	$ 513
Power purchased	175	28	147	199	221
Other operation and maintenance expenses	346	66	280	320	275
Depreciation and amortization	145	26	119	133	136
	$ 1,161	$ 198	$ 963	$ 1,086	$ 1,145

The changes in operating expenses were as follows:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Fuel for electric generation	$ 61	$ (79)
Power purchased	(24)	(22)
Other operation and maintenance expenses	26	45
Depreciation and amortization	12	(3)
	$ 75	$ (59)

Fuel for Electric Generation

The $61 million increase from 2009 to 2010 and $79 million decrease from 2008 to 2009 were primarily due to:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Fuel usage volumes (a)	$ 77	$ (97)
Commodity costs for coal	(15)	18
Other	(1)	-
	$ 61	$ (79)

(a) Fuel usage volumes increased in 2010 compared 2009 due to increased native load sales. Fuel usage volumes decreased in 2009 compared to 2008 due to decreased native load and wholesale sales.

Power Purchased Expense

The $24 million decrease from 2009 to 2010 and $22 million decrease from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Power purchased from OMU	$ (40)	$ 12
Purchases from LG&E due to volume (a)	(5)	(2)
Demand payments for third party purchases	(2)	1
Prices for purchases used to serve retail customers	7	(14)
Third party purchased volumes for native load (b)	7	(6)
OMU settlement received in 2009	6	(6)
Purchases from LG&E due to prices	3	(7)
	$ (24)	$ (22)

(a) Purchased volumes from LG&E decreased in 2010 compared to 2009 primarily due to increased consumption by residential customers at LG&E as the result of increased cooling and heating degree days, increased coal-fired generation outages in the first six months of 2010 and higher energy usage by industrial customers as a result of improved economic conditions.

Purchased volumes from LG&E decreased in 2009 compared to 2008 due to LG&E's increased scheduled outages at coal-fired generation units during the fourth quarter of 2009. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between the Utilities.

(b) Third party purchase volumes with counterparties other than OMU increased in 2010 compared to 2009 primarily due to the termination of the OMU agreement. Third party purchase volumes with counterparties other than OMU decreased in 2009 compared to 2008 primarily due to availability of power for native load customers from the OMU agreement. See Note 13, Commitments and Contingencies, for further discussion of the OMU settlement.

Other Operation and Maintenance Expenses

The $26 million increase from 2009 to 2010 was primarily due to $22 million of increased other operation expenses and $4 million of increased maintenance expenses. The $45 million increase from 2008 to 2009 was primarily due to $30 million of increased other operation expenses and $15 million of increased maintenance expenses.

Other Operation Expenses:

The $22 million increase from 2009 to 2010 and $30 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Administrative and general expense (a)	$ 9	$ 3
Transmission expense (b)	5	-
Bad debt expense (c)	4	(1)
Steam expense (d)	4	7
Generation expense	2	(2)
DSM program spending	-	9
Legal expenses (e)	-	(6)
Other power supply	(1)	-
Pension expense (f)	(2)	20
Other	1	-
	$ 22	$ 30

(a) Administrative and general expense increased in 2010 compared 2009 primarily due to higher labor expense and insurance expense, partially offset by lower IT expense related to the implementation of the Customer Care Solution system in 2009. Administrative and general expense increased in 2009 compared to 2008 primarily due to increased consulting fees for software training and increased labor and benefit costs.

(b) Transmission expense increased in 2010 compared to 2009 primarily due to a settlement agreement with a third party and the establishment of a regulatory asset approved by the Kentucky Commission for the EKPC settlement in 2009, net of twelve months of amortization expense recorded in 2010.

(c) Bad debt expense increased in 2010 compared to 2009 due to higher billed revenues, higher late payment charges and a higher net charge-off percentage.

(d) Steam expense increased in 2010 compared to 2009 primarily due to increased generation in 2010. Steam expense increased in 2009 compared to 2008 primarily due to the utilization of SCRs year-round.

(e) Legal expenses decreased in 2009 compared to 2008 primarily due to OMU expenses in 2008. See Note 13, Commitments and Contingencies, for further information regarding the OMU settlement.

(f) Pension expense decreased in 2010 compared to 2009 primarily due to favorable asset performance in 2009 and increased in 2009 compared to 2008 primarily due to unfavorable asset performance in 2008.

Other Maintenance Expenses:

The $4 million increase from 2009 to 2010 and $15 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Generation expense (a)	$ 3	$ -
Steam expense (b)	2	7
Administrative and general expense	2	1
Transmission expense	-	2
Distribution expense (c)	(3)	5
	$ 4	$ 15

(a) Generation expense increased in 2010 compared to 2009 primarily due to the overhaul of Paddy's Run Unit 13.
(b) Steam expense increased in 2009 compared to 2008 due to increased scope of work for scheduled outages.
(c) Distribution expense decreased in 2010 compared to 2009 primarily due to higher storm cost in 2009, partially offset by higher tree trimming expense in 2010. Distribution expense increased in 2009 compared to 2008 primarily due to increased repairs, higher tree trimming expense and higher storm related expense.

Equity in Earnings of Unconsolidated Venture

The $2 million increase in equity in earnings of unconsolidated venture, from 2009 to 2010, was primarily due to higher earnings from EEI resulting from increased market prices for electric energy and the $29 million decrease from 2008 to 2009 was primarily due to lower earnings resulting from decreased market prices for electric energy.

Interest Expense

The $3 million increase from 2009 to 2010 and $3 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Bond interest expense (a)	$ 8	$ (8)
Interest expense to affiliated companies (b)	(5)	11
	$ 3	$ 3

(a) Bond interest expense increased in 2010 compared to 2009 due to the issuance of first mortgage bonds in November 2010. Bond interest expense decreased in 2009 compared to 2008 due to lower interest rates on pollution control bonds. See Note 11, Long-Term Debt, for further information.
(b) Interest expense to affiliated companies decreased in 2010 compared to 2009 primarily due to notes payable to Fidelia being paid in full in November 2010, as a result of the PPL acquisition. Interest expense to affiliated companies increased in 2009 compared to 2008 primarily due to the

issuance of additional debt ($13 million), which was partially offset by lower interest rates on intercompany short-term borrowings.

Other Income (Expense) – Net

The $7 million decrease in other income (expense) – net from 2009 to 2010 and the $3 million decrease in other income (expense) – net from 2008 to 2009 were primarily due to the discontinuance of the allowance for funds used during construction on ECR projects as a result of the FERC rate case.

Income Tax Expense

See Note 10, Income Taxes, for a reconciliation of differences between the U.S. federal income tax expense at statutory rates and KU's income tax expense.

2011 Outlook

KU projects higher earnings in 2011 compared with 2010 as a net result of higher retail revenues and lower financing costs due to the issuance of first mortgage bonds in late 2010, partially offset by higher operation and maintenance expenses and depreciation. Retail revenues are expected to increase as a result of the 2010 Kentucky rate case and recoveries associated with its environmental investments. Operation and maintenance expenses and depreciation are expected to increase due to placing TC2 in service in January 2011. See Risk Factors for a discussion of the risk factors that may impact the 2011 outlook.

Financial Condition

Liquidity and Capital Resources

KU expects to continue to have adequate liquidity available through operating cash flows, cash and cash equivalents and its credit facilities. KU currently has no plans to access debt capital markets in 2011.

KU's cash flows from operations and access to cost-effective bank and capital markets are subject to risks and uncertainties including, but not limited to, the following:

- changes in market prices for electricity;
- potential ineffectiveness of the trading, marketing and risk management policy and programs used to mitigate KU's risk exposure to adverse electricity and fuel prices and interest rates;
- operational and credit risks associated with selling and marketing products in the wholesale power markets;
- unusual or extreme weather that may damage KU's transmission and distribution facilities or affect energy sales to customers;
- unavailability of generating units (due to unscheduled or longer than anticipated generation outages, weather and natural disasters) and the resulting loss of revenues and additional costs of replacement electricity;
- ability to recover and timeliness and adequacy of recovery of costs;
- costs of compliance with existing and new environmental laws;

- any adverse outcome of legal proceedings and investigations with respect to KU's current and past business activities;
- deterioration in the financial markets that could make obtaining new sources of bank and capital markets funding more difficult and more costly; and
- a downgrade in KU's credit ratings that could adversely affect its ability to access capital and increase the cost of credit facilities and any new debt.

See the Risk Factors section for further discussion of risks and uncertainties affecting KU's cash flows.

At December 31, KU had the following:

	Successor	Predecessor
	2010	2009
Cash and cash equivalents	$ 3	$ 2
Current portion of long-term debt (a)	$ -	$ 228
Current portion of long-term debt to affiliated company (b)	-	33
Notes payable to affiliated companies (c)	10	45
	$ 10	$ 306

(a) 2009 amount represents Carroll County 2002 Series A and B, 2004 Series A, 2006 Series B and 2008 Series A; Muhlenberg County 2002 Series A; and Mercer County 2000 Series A and 2002 Series A pollution control bonds subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. The Successor has classified these bonds as long-term because the Company has the intent and ability to utilize its $400 million credit facility which matures in December 2014, to fund any mandatory purchases. The Predecessor classified these bonds as the current portion of long-term debt due to the tender for purchase provisions. The Predecessor presentation and the Successor presentation are both appropriate under GAAP. See Note 1, Summary of Significant Accounting Policies, and Note 11, Long-Term Debt, for further information.

(b) 2009 amount represents debt owed to an E.ON affiliate, which was repaid in November 2010. See Note 11, Long-Term Debt, for further information.

(c) Amounts represent borrowings under KU's intercompany money pool agreement wherein LKE and/or LG&E make funds available to KU at market-based rates of up to $400 million. See Note 12, Notes Payable and Other Short-Term Obligations, for further information.

A condensed table of cash flows for the following periods in 2010, 2009 and 2008 is presented below. The Predecessor period, January 1, 2010 through October 31, 2010, and the Successor period, November 1, 2010 through December 31, 2010, were aggregated without further adjustment for purposes of comparison with the same periods in 2009 and 2008.

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Net cash provided by (used in) operating activities	$ 372	$ 28	$ 344	$ 253	$ 292
Net cash provided by (used in) investing activities	(427)	(87)	(340)	(507)	(695)
Net cash provided by (used in) financing activities	56	58	(2)	254	405
Change in cash and cash equivalents	$ 1	$ (1)	$ 2	$ -	$ 2

Operating Activities

Net cash provided by operating activities increased by 47%, or $119 million, in 2010 compared with 2009, primarily as a result of increased earnings, increased collections from the ECR mechanism and lower storm expenses. These increases in cash flow were partially offset by higher interest payments due to an accelerated settlement with the previous owner and higher 2010 income tax payments due to higher taxable income and investment tax credit benefits received in 2009.

Net cash provided by operating activities decreased by 13%, or $39 million, in 2009 compared with 2008, primarily as a result of higher storm expenses, decreased earnings and unfavorable changes in working capital. These decreases in cash flow were partially offset by lower income tax payments due to lower taxable income and investment tax credit benefits received.

KU expects to achieve relatively stable cash flows from operations during the next three years although future cash flows may be significantly impacted by changes in economic conditions or new environmental and tax regulations.

Investing Activities

The primary use of cash in investing activities is capital expenditures. See “Forecasted Uses of Cash" for detail regarding projected capital expenditures for the years 2011 through 2013.

Net cash used in investing activities decreased by 16%, or $80 million, in 2010 compared with 2009, primarily as a result of a decrease of $89 million in capital expenditures, partially offset by a decrease of $9 million from restricted cash collections.

Net cash used in investing activities decreased by 27%, or $188 million, in 2009 compared with 2008, primarily as a result of a decrease of $180 million in capital expenditures and a increase of $8 million from restricted cash collections.

Financing Activities

Net cash provided by financing activities was $56 million in 2010 compared with $254 million in 2009. In spite of significant new debt issuances associated with the repayments to E.ON affiliates in connection with PPL's acquisition of the Company, cash provided by financing was less in 2010 due to lower increases in debt in 2010 and the payment of dividends in 2010; whereas, KU received equity contributions in 2009.

Net cash provided by financing activities was $254 million in 2009 compared with $405 million in 2008. The lower level of cash provided by financing in 2009 was the result of lower debt issuance to affiliated companies and lower levels of equity contributions received.

In the two months of 2010 following the acquisition, cash provided by financing activities of the Successor primarily consisted of the issuance of first mortgage bonds totaling $1,489 million after discounts and the issuance of intercompany notes totaling $1,331 million to a PPL subsidiary to repay debt due to an E.ON affiliate upon the closing of the sale. These amounts were offset by the repayment of $1,331 million to an E.ON affiliate upon the closing of the sale, the repayment of $1,331 million to a PPL affiliate upon the issuance of the first mortgage bonds, the repayment of $83 million of short-term borrowings due to an affiliated company and the payment of $17 million of debt issuance costs.

In 2010, cash used in financing activities by the Predecessor primarily consisted of the payment of $50 million of dividends to LKE mostly offset by increases in short-term borrowings due to an affiliated company totaling $48 million.

In 2009, cash provided by financing activities primarily consisted of the issuance of $150 million of intercompany notes to an E.ON affiliate, the receipt of capital contributions from LKE totaling $75 million and a $29 million increase in short-term borrowings due to an affiliated company.

In 2008, cash provided by financing activities primarily consisted of the issuance of $250 million of intercompany notes to an E.ON affiliate, the receipt of capital contributions from LKE totaling $145 million and a $7 million reduction in short-term borrowings due to an affiliated company. In addition, KU reacquired pollution control bonds totaling $80 million, reissued $63 million of that $80 million and issued $77 million of new pollution control bonds. Of the $77 million, $60 million was used to retire prior pollution control bonds, including the remaining $17 million which had been reacquired by the Company. This resulted in a cash receipt of $17 million to KU.

KU's debt financing activity in 2010 was:

	Issuances (a)	Retirements
Short-term borrowings from affiliated company – net change	$ -	$ (35)
Other borrowings from affiliated company	1,331	(1,331)
Borrowings from an E.ON affiliate	-	(1,331)
Issuance of bonds	1,489	-
Net change in debt financing	$ 2,820	$ (2,697)

(a) Issuances are net of pricing discounts, where applicable.

See Note 11, Long-Term Debt, for further information.

Working Capital Deficiency

As of December 31, 2009, KU had a working capital deficiency of $203 million, primarily due to the current portion of long-term debt to affiliated company totaling $33 million and $228 million of tax-exempt bonds which allow the investors to put the bonds back to the Company causing them to be classified as “Current portion of long-term debt.” As of December 31, 2010, the Company no longer had a working capital deficiency because the current portion of long-term debt to affiliated company was paid off in conjunction with the PPL acquisition, and the $228 million of tax-exempt bonds were no longer classified as “Other current liabilities” by the Successor because the Company has the intent and ability to utilize its $400 million credit facility which expires in December 2014 to fund any mandatory purchases. See Note 11, Long-Term Debt, for further information.

Auction Rate Securities

Auctions for auction rate securities issued by KU continued to fail throughout 2010. See Note 11, Long-Term Debt, for further discussion.

Forecasted Sources of Cash

KU expects to continue to have adequate sources of cash available in the near term, including access to external financing, financing from affiliates and/or infusions of capital from LKE. Regulatory approvals are required for KU to incur additional debt. The FERC and the Virginia Commission authorize the issuance of short-term debt while the Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority authorize the issuance of long-term debt. In November 2009, KU received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. KU also has authorization from the Virginia Commission that expires at the end of 2011, allowing short-term borrowing of up to $400 million. Short-term funds are made available via the Company’s participation in an intercompany money pool agreement wherein LKE and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) up to $400 million or via the $400 million Revolving Credit Agreement discussed below. KU currently believes this authorization and these facilities, together with the Company’s credit facilities discussed below, provide the necessary flexibility to address any liquidity needs.

Credit Facilities

On November 1, 2010, KU entered into a $400 million unsecured Revolving Credit Agreement with a group of banks. Under this new credit facility, which expires on December 31, 2014, KU has the ability to make cash borrowings and to request the lenders to issue letters of credit. Borrowings will generally bear interest at LIBOR-based rates plus a spread, depending upon KU’s senior unsecured long-term debt rating. The new credit facility contains financial covenants requiring KU’s debt to total capitalization to not exceed 70% and other customary covenants. As of December 31, 2010, KU’s debt to total capitalization was 41% as calculated pursuant to the credit agreement. Under certain conditions, KU may request that the facility’s capacity be increased by up to $100 million. This new credit facility

replaced an existing bilateral line of credit totaling $35 million that was terminated November 1, 2010. As of December 31, 2010, there was no outstanding balance under the new credit facility, but there were $198 million of letters of credit outstanding to support outstanding bonds totaling $195 million. KU will utilize unused credit facility and money pool balances to fund working capital needs as they arise. See Note 12, Notes Payable and Other Short-Term Obligations, for further information regarding the Company's credit facilities.

Contributions from LKE

LKE may make capital contributions to KU, which can be used for general business purposes.

Long-Term Debt

KU currently does not plan to issue any new long-term debt in 2011.

Forecasted Uses of Cash

In addition to expenditures required for normal operating activities, such as fuel for electric generation, power purchased, payroll and taxes; KU currently expects to incur future cash outflows for capital expenditures, various contractual obligations and the payment of dividends.

Capital Requirements

KU's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of its service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. KU plans to fund capital expenditures through operating cash flows, the credit facility and, if needed, the issuance of long-term debt. KU expects its capital expenditures for the three year period ending December 31, 2013, to total approximately $1,406 million, consisting primarily of the following:

Construction of coal combustion residual storage structures	$ 346
Construction of environmental controls and capacity replacement	302
Construction of distribution and metering assets	260
Construction of generation assets	206
Construction of transmission assets	129
Recoverable environmental assets	99
Information technology projects	39
Other projects	25
	$ 1,406

The Company's capital program will focus primarily on compliance with existing or anticipated EPA environmental regulations, aging infrastructure and the need for increased storage capacity for coal combustion by-product materials over the next several years. This program may also be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, changes in commodity prices and labor rates and other regulatory requirements. In particular, climate change initiatives, whether via legislative, regulatory or market channels, could restrict or disadvantage power generation from higher-

carbon sources. Therefore, KU has included estimates regarding significant additional capital expenditures related to pending environmental regulations and legislation. These estimates are subject to final regulations and least cost analysis based on engineering studies. To the extent financial markets see climate change as a potential risk, KU may face reduced access to or increased costs in capital markets. Capital expenditures for KU associated with such actions are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary.

See the Contractual Obligations table below and Note 13, Commitments and Contingencies, for further information concerning commitments.

Contractual Obligations

The following is provided to summarize contractual cash obligations for periods after December 31, 2010. KU anticipates cash from operations and external financing will be sufficient to fund future obligations. See the Statements of Capitalization.

	Payments Due by Period						
	2011	2012	2013	2014	2015	Thereafter	Total
Short-term debt (a)	$ 10	$ -	$ -	$ -	$ -	$ -	$ 10
Long-term debt (b)	-	-	-	-	250	1,601	1,851
Interest on long-term debt (c)	67	69	72	75	78	1,414	1,775
Operating leases (d)	8	7	5	5	3	1	29
Unconditional power purchase obligations (e)	9	10	10	10	10	114	163
Coal and natural gas purchase obligations (f)	439	200	144	93	91	14	981
Pension benefit plan obligations (g)	18	24	28	10	7	60	147
Postretirement benefit plan obligations (h)	5	6	6	6	6	33	62
Construction obligations (i)	113	3	-	-	-	-	116
Other obligations (j)	3	3	-	-	-	-	6
	$ 672	$ 322	$ 265	$ 199	$ 445	$ 3,237	$ 5,140

This table does not reflect contingent obligations. See Note 13, Commitments and Contingencies, for further information on contingent obligations.

(a) Represents borrowings due to affiliates within one year.
(b) Reflects principal maturities only based on legal maturity dates and includes the current portion of long-term debt.
(c) Assumes interest payments through maturity. The payments herein are subject to change as payments for debt that is or becomes variable-rate debt have been estimated.
(d) Represents future operating lease payments.
(e) Represents future minimum payments under OVEC power purchase agreements through March 13, 2026.
(f) Represents contracts to purchase coal, natural gas and natural gas transportation.

(g) Represents projected cash flows for funding the pension benefit plans as calculated by the actuary. For pension funding information see Note 9, Pension and Other Postretirement Benefit Plans.
(h) Represents projected cash flows for the postretirement benefit plan as calculated by the actuary. For postretirement funding information, see Note 9, Pension and Other Postretirement Benefit Plans.
(i) Represents construction commitments, including commitments for the Brown SCR and the Brown and Ghent landfill construction including associated material transport systems for coal combustion residual.
(j) Represents other contractual obligations including the SPP and TVA coordination agreements.

Pension and Postretirement Benefit Plans

See Application of Critical Accounting Policies and Estimates for discussion regarding discretionary contributions to the pension and postretirement benefit plans in 2011.

Dividends

Future dividends may be declared at the discretion of KU's Board of Directors, payable to its sole shareholder, LKE. As discussed in Note 12, Notes Payable and Other Short-Term Obligations, KU's dividend payments are limited under a covenant in its $400 million revolving line of credit facility. This covenant restricts the debt to total capital ratio to not more than 70%. KU is subject to Section 305(a) of the Federal Power Act, which makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in capital account." The meaning of this limitation has never been clarified under the Federal Power Act. KU believes, however, that this statutory restriction, as applied to its circumstances, would not be construed or applied by the FERC to prohibit the payment from retained earnings of dividends that are not excessive and are for lawful and legitimate business purposes.

Purchase, Redemption or Remarketing of Debt Securities

KU will continue to evaluate purchasing, redeeming or remarketing outstanding debt securities and may decide to take action depending upon prevailing market conditions and available cash.

<u>Credit Ratings</u>

KU's credit ratings reflect the views of three national rating agencies. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. In October 2010, one national rating agency revised downward the short-term credit rating of the pollution control bonds and the issuer rating of the Company as a result of the then pending acquisition by PPL. Another raised the long-term rating of the pollution control bonds as a result of the addition of the first mortgage bonds as collateral. In October 2010, a third national rating agency provided an initial rating of the Company's pollution control bonds and first mortgage bonds. See Note 11, Long-Term Debt, for a discussion of downgrade actions in 2009 and 2008 related to the pollution control bonds caused by a change in the rating of the entity insuring those bonds.

Ratings Triggers

KU has various derivative and non-derivative contracts, including contracts for the sale and purchase of electricity and fuel and commodity transportation, which contain provisions requiring KU to post additional collateral, or permit the counterparty to terminate the contract if KU's credit rating were to fall below investment grade. See Note 5, Derivative Financial Instruments, for a discussion of Credit Risk Related Contingent Features, including a discussion of the potential additional collateral that would have been required for derivative contracts in a net liability position at December 31, 2010. At December 31, 2010, if KU's credit ratings had been below investment grade, KU would have been required to prepay or post an additional $16 million of collateral to counterparties for both derivative and non-derivative commodity and commodity-related contracts used in its generation, marketing and trading operations.

Off-Balance Sheet Arrangements

KU has very limited off-balance sheet activity. See Note 13, Commitments and Contingencies, for further discussion.

Risk Management

Credit Risk

KU is exposed to potential losses as a result of nonperformance by counterparties of their contractual obligations. KU maintains credit policies and procedures to limit counterparty credit risk including evaluating credit ratings and financial information along with having certain counterparties post margin if the credit exposure exceeds certain thresholds. See Note 5, Derivative Financial Instruments, for information regarding risk management activities.

KU is exposed to potential losses as a result of nonpayment by customers. The Company maintains an allowance for doubtful accounts composed of accounts aged more than four months. Accounts are written off as management determines them uncollectible. See Application of Critical Accounting Policies and Estimates and Note 1, Summary of Significant Accounting Policies, for further discussion.

Certain of the Company's derivative instruments contain provisions that require it to provide immediate and on-going collateralization on derivative instruments in net liability positions based upon the Company's credit ratings from each of the major credit rating agencies. See Note 5, Derivative Financial Instruments, for information regarding exposure and the risk management activities.

Liquidity Risk

KU expects to continue to have access to adequate sources of liquidity through operating cash flows, cash and cash equivalents, credit facilities and/or infusion of capital from its parent. See Financial Condition - Liquidity and Capital Resources for an expanded discussion of KU's liquidity position and a discussion of its forecasted sources of cash.

Securities Price Risk

KU has securities price risk through its participation in defined benefit pension and postretirement benefit plans. Declines in the market price of debt and equity securities could impact contribution requirements. See Application of Critical Accounting Policies and Estimates - Defined Benefits for a discussion of the assumptions and sensitivities regarding the defined benefit pension and postretirement benefit plans assumptions.

Interest Rate and Commodity Price Risk

KU is subject to interest rate and commodity price risk related to on-going business operations. It currently manages commodity risks using derivative instruments, including swaps and forward contracts. The Company's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At December 31, 2010, no interest rate swaps were in effect for KU. At December 31, 2010, the Company's annual exposure to increased interest expense, based on a 10% increase in interest rates, was less than $1 million.

KU manages price risk by conducting energy trading activities through forward financial transactions. The following chart sets forth the net fair value of KU's commodity derivative contracts. See Note 5 Derivative Financial Instruments, for further information.

	Successor	Predecessor	
	December 31, 2010 (a)	October 31, 2010 (a)	December 31, 2009
Fair value of contracts outstanding at the beginning of the period	$ -	$ -	$ 1
Contracts realized or otherwise settled during the period	-	-	
Fair value of new contracts entered into during the period	-	-	-
Changes in fair value attributable to changes in valuation techniques	-	-	-
Other changes in fair value	-	-	(1)
Fair value of contracts outstanding at the end of the period	$ -	$ -	$ -

(a) 2010 activity is less than $1 million.

Related Party Transactions

KU and its Parent, LKE and subsidiaries of LKE engage in related party transactions. See Note 15, Related Party Transactions, for further information.

KU is not aware of any material ownership interest or operating responsibility by the executive officers of KU in outside partnerships, including leasing transactions with variable interest entities, or entities doing business with KU.

Acquisitions, Development and Divestitures

KU and LG&E have been constructing a new 760-Mw capacity base-load, coal-fired unit, TC2, which is jointly owned by KU (60.75%) and LG&E (14.25%), together with IMEA and IMPA (combined 25%). With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. See Note 13, Commitments and Contingencies, for further information.

KU continuously re-examines development projects based on market conditions and other factors to determine whether to proceed, to cancel or to expand the projects.

Application of Critical Accounting Policies and Estimates

The financial statements of KU are prepared in compliance with GAAP. The application of these principles necessarily involves judgments regarding future events, including legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but also on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied has not changed. KU's senior management has reviewed the significant and critical accounting policies with the relevant governing bodies of the Company and its parent, as applicable.

An accounting policy is deemed to be critical if it requires an accounting estimate to be made based on assumptions about matters that are highly uncertain at the time the estimate is made, if different estimates reasonably could have been used or if changes in the estimate that are reasonably possible could materially impact the financial statements. Management believes the following critical accounting policies reflect the significant estimates and assumptions used in the preparation of the Financial Statements.

Price Risk Management

See Financial Condition - Risk Management.

Regulatory Mechanisms

KU is a cost-based rate-regulated utility. As a result, the financial statements reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise be charged to expense. Likewise, regulatory liabilities are recognized for obligations expected to be returned through future regulated customer rates. The effect of such transactions or events would otherwise be reflected as income. In certain cases, regulatory liabilities are recorded based on the understanding with the regulator that current rates are being set to recover costs that are expected to be incurred in the future. The regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. The accounting

for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC, the Kentucky Commission, the Virginia Commission or the Tennessee Regulatory Authority. See Note 3, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Defined Benefits

KU employees benefit from both funded and unfunded retirement benefit plans. See Note 1, Summary of Significant Accounting Policies, for information about policy changes between the Predecessor and Successor and the accounting for defined benefits including KU's method of amortizing gains and losses. KU makes various assumptions in arriving at pension and other postretirement benefit costs and obligations. The major assumptions include:

- KU's selection of discount rates is based on the Mercer Pension Discount Yield Curve (Predecessor) and the Towers Watson Yield Curve (Successor).
- KU's selection of rate of salary growth is based on historical data that includes employees' periodic pay increases and promotions, which are used to project employees' pension benefits at retirement.
- KU determines the expected long-term return on plan assets based on the current level of expected return on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class is then weighted based on the current asset allocation.
- KU's management projects health care cost trends based on past health care costs, the near-term outlook and an assessment of likely long-term trends.

The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under the defined benefit pension plans. The return on investments within the plans was approximately 12% for the year ended December 31, 2010. The benefit plan assets and obligations are re-measured annually using a December 31 measurement date. Due to the PPL acquisition, the benefit plan assets and obligations were also re-measured at October 31, 2010. The Company's 2010 pension cost was approximately $3 million less than 2009. The Company anticipates its 2011 pension cost will be approximately $3 million less than the 2010 expense. The amount of future funding will depend upon the actual return on plan assets, the discount rate and other factors, but the Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. The Company made discretionary contributions to its pension plan of $13 million in 2010 and 2009, respectively. In January 2011, KU contributed $43 million to its pension plan. See Note 18, Subsequent Events, for further information.

See Note 9, Pension and Other Postretirement Benefit Plans, for further information on defined benefits including sensitivity analysis expressing potential changes in expected returns that would result from hypothetical changes to assumptions and estimates, expected rate of return assumptions and health care trends.

Asset Impairment

KU performs a quarterly review to determine if an impairment analysis is required for long-lived assets that are subject to depreciation or amortization. This review identifies changes in circumstances indicating that a long-lived asset's carrying value may not be recoverable. An impairment analysis will be performed if warranted based on the review. For these long-lived assets, such events or changes in circumstances which may indicate an impairment analysis is required include:

- a significant decrease in the market price of an asset;
- a significant adverse change in the manner in which an asset is being used or in its physical condition;
- a significant adverse change in legal factors or in the business climate;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of an asset;
- a current-period operating or cash flow loss combined with a history of losses or a forecast that demonstrates continuing losses;
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its previously estimated useful life; and
- a significant change in the physical condition of an asset.

For a long-lived asset, impairment is recognized when the carrying amount of the asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset is impaired, an impairment loss is recorded to adjust the asset's carrying value to its estimated fair value. Management must make significant judgments to estimate future cash flows including the useful lives of long-lived assets, the fair value of the assets and management's intent to use the assets. KU did not recognize an impairment of any long-lived asset in 2010.

Effective with PPL's acquisition of LKE on November 1, 2010, KU recorded $607 million of goodwill. At December 31, 2010, KU's goodwill remained unchanged. GAAP requires goodwill to be tested for impairment on an annual basis or more frequently if events or circumstances indicate that assets may be impaired. KU performs its annual goodwill impairment test in the fourth quarter. See Note 7, Goodwill and Intangible Assets, for further discussion.

Goodwill is tested for impairment using a two-step approach. In step 1, the Company identifies a potential impairment by comparing the estimated fair value of the Company (the goodwill reporting unit) to its carrying value, including goodwill, on the measurement date. If the estimated fair value exceeds its carrying amount, goodwill is not considered impaired. If the carrying amount exceeds the estimated fair value, the second step is performed to measure the amount of impairment loss, if any.

The second step requires a calculation of the implied fair value of goodwill. The implied fair value of goodwill is determined in the same manner as the amount of goodwill in a business combination. That is, the estimated fair value is allocated to all of KU's assets and liabilities as if KU had been acquired in a business combination and the estimated fair value of KU was the price paid. The excess of the estimated fair value of KU over the amounts assigned to its assets and liabilities is the implied fair value of goodwill. The implied fair value of goodwill is then compared with the carrying amount of that goodwill. If the

carrying amount exceeds the implied fair value, an impairment loss is recognized in an amount equal to that excess. The loss recognized cannot exceed the carrying amount of the reporting unit's goodwill.

Determining the fair value of KU is judgmental in nature and involves the use of significant estimates and assumptions. These estimates and assumptions can include revenue growth rates and operating margins used to calculate projected future cash flows, risk adjusted discount rates and future economic and market conditions.

KU tested goodwill for impairment in the fourth quarter of 2010 and no impairment was recognized. See Note 7, Goodwill and Intangible Assets, for further discussion.

Loss Accruals

KU accrues losses for the estimated impacts of various conditions, situations or circumstances involving uncertain or contingent future outcomes. For loss contingencies, the loss must be accrued if (1) information is available that indicates it is probable that a loss has been incurred, given the likelihood of the uncertain future events and (2) the amount of the loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." KU does not record the accrual of contingencies that might result in gains, unless recovery is assured. KU continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events.

The accounting aspects of estimated loss accruals include (1) the initial identification and recording of the loss, (2) the determination of triggering events for reducing a recorded loss accrual and (3) the ongoing assessment as to whether a recorded loss accrual is sufficient. All three of these aspects require significant judgment by KU's management. KU uses its internal expertise and outside experts (such as lawyers and engineers), as necessary, to help estimate the probability that a loss has been incurred and the amount or range of the loss.

KU has identified certain other events that could give rise to a loss, but that do not meet the conditions for accrual. Such events are disclosed, but not recorded, when it is reasonably possible that a loss has been incurred. Accounting guidance defines "reasonably possible" as cases in which "the future event or events occurring is more than remote, but less than likely to occur." See Note 13, Commitments and Contingencies, for disclosure of other potential loss contingencies that have not met the criteria for accrual.

When an estimated loss is accrued, KU identifies, where applicable, the triggering events for subsequently adjusting the loss accrual. The triggering events generally occur when the contingency has been resolved and the actual loss is incurred, or when the risk of loss has diminished or been eliminated. The following are some of the triggering events that provide for the adjustment of certain recorded loss accruals:

- Allowances for uncollectible accounts are reduced when accounts are written off after prescribed collection procedures have been exhausted, a better estimate of the allowance is determined or underlying amounts are ultimately collected.
- Environmental and other litigation contingencies are reduced when the contingency is resolved, KU makes actual payments, a better estimate of the loss is determined or the loss is no longer considered probable.

KU reviews its loss accruals on a regular basis to assure that the recorded potential loss exposures are appropriate. This involves ongoing communication and analyses with internal and external legal counsel, engineers, operation management and other parties. This review may result in the increase or decrease of the loss accrual.

Asset Retirement Obligations

KU is required to recognize a liability for legal obligations associated with the retirement of long-lived assets. The initial obligation is measured at its estimated fair value. An equivalent amount is recorded as an increase in the value of the capitalized asset and allocated to expense over the useful life of the asset. Until the obligation is settled, the liability is increased, through the recognition of accretion expense in the Statements of Income, for changes in the obligation due to the passage of time. An offsetting regulatory asset is recognized to reverse the depreciation and accretion expense related to the ARO such that there is no income statement impact. The regulatory asset is relieved when the ARO has been settled. An ARO must be recognized when incurred if the fair value of the ARO can be reasonably estimated.

In determining AROs, management must make significant judgments and estimates to calculate fair value. Fair value is developed using an expected present value technique based on assumptions of market participants that considers estimated retirement costs in current period dollars that are inflated to the anticipated retirement date and then discounted back to the date the ARO was incurred. Changes in assumptions and estimates included within the calculations of the fair value of AROs could result in significantly different results than those identified and recorded in the financial statements. Estimated ARO costs and settlement dates, which affect the carrying value of various AROs and the related assets, are reviewed periodically to ensure that any material changes are incorporated into the estimate of the obligations. Any change to the capitalized asset is amortized over the remaining life of the associated long-lived asset. See Note 4, Asset Retirement Obligations, for further information on AROs.

At December 31, 2010, KU had AROs totaling $54 million recorded on the Balance Sheets. Of the total amount, $35 million, or 65%, relates to KU's ash ponds and landfills. The most significant assumptions surrounding AROs are the forecasted retirement costs, the discount rates and the inflation rates. A variance in the forecasted retirement costs, the discount rates or the inflation rates could have a significant impact on the ARO liabilities.

The following chart reflects the sensitivities related to KU's ARO liabilities for ash ponds and landfills as of December 31, 2010:

	Change in Assumption	Impact on ARO Liability
Retirement cost	10%/(10)%	$4/$(4)
Discount rate	0.25%/(0.25)%	$(2)/$1
Inflation rate	0.25%/(0.25)%	$2/$(2)

Income Tax Uncertainties

Significant management judgment is required in developing KU's provision for income taxes primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and the determination of deferred tax assets, liabilities and valuation allowances.

Significant management judgment is required to determine the amount of benefit recognized related to an uncertain tax position. KU evaluates its tax positions following a two-step process. The first step requires an entity to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires an entity to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. KU's management considers a number of factors in assessing the benefit to be recognized, including negotiation of a settlement.

On a quarterly basis, KU reassesses its uncertain tax positions by considering information known at the reporting date. Based on management's assessment of new information, KU may subsequently recognize a tax benefit for a previously unrecognized tax position, de-recognize a previously recognized tax position or re-measure the benefit of a previously recognized tax position. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact KU financial statements in the future.

The balance sheet classification of unrecognized tax benefits and the need for valuation allowances to reduce deferred tax assets also require significant management judgment. KU classifies unrecognized tax benefits as current, to the extent management expects to settle an uncertain tax position, by payment or receipt of cash, within one year of the reporting date. Valuation allowances are initially recorded and reevaluated each reporting period by assessing the likelihood of the ultimate realization of a deferred tax asset. Management considers a number of factors in assessing the realization of a deferred tax asset, including the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies. Any tax planning strategy utilized in this assessment must meet the recognition and measurement criteria utilized by KU to account for an uncertain tax position. See Note 10, Income Taxes, for the required disclosures.

At December 31, 2010, KU's existing reserve exposure to either increases or decreases in unrecognized tax benefits during the next 12 months is less than $1 million. This change could result from subsequent recognition, de-recognition and/or changes in the measurement of uncertain tax positions. The events that could cause these changes are direct settlements with taxing authorities, litigation, legal or administrative guidance by relevant taxing authorities and the lapse of an applicable statute of limitations.

Purchase Price Allocation

On November 1, 2010, PPL completed the acquisition of KU's parent. In accordance with accounting guidance on business combinations, the identifiable assets acquired and the liabilities assumed were measured at fair value at the acquisition date. Fair value is defined as the price that would be received to

sell an asset or paid to transfer a liability in an orderly transaction between market participants. The excess of the purchase price over the estimated fair value of the identifiable net assets is recorded as goodwill.

The determination and allocation of fair value to the identifiable assets acquired and liabilities assumed was based on various assumptions and valuation methodologies requiring considerable management judgment, including estimates based on key assumptions of the acquisition and historical and current market data. The most significant variables in these valuations were the discount rates, the number of years on which to base cash flow projections, as well as the assumptions and estimates used to determine cash inflows and outflows. Although the assumptions applied were reasonable based on information available at the date of acquisition, actual results may differ from the forecasted amounts and the difference could be material.

For purposes of measuring the fair value of the majority of property, plant and equipment and regulatory assets acquired and regulatory liabilities assumed, KU determined that fair value was equal to net book value at the acquisition date because KU's operations are conducted in a regulated environment and the regulatory commissions allow for earning a rate of return on the book value of a majority of the regulated asset bases at rates determined to be fair and reasonable. As there is no current prospect for deregulation in KU's operating area, it is expected that these operations will remain in a regulated environment for the foreseeable future, therefore management has concluded that the use of these assets in the regulatory environment represents their highest and best use and a market participant would measure the fair value of these assets using the regulatory rate of return as the discount rate, thus resulting in fair value equal to book value.

The fair value of intangible assets and liabilities (e.g. contracts that have favorable or unfavorable terms relative to market), including coal contracts and power purchase agreements, as well as emission allowances, have been reflected on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the acquisition. As a result, management believes the regulatory assets and liabilities created to offset the fair value adjustments meet the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. KU's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU also considered whether a separate fair value should be assigned to KU's rights to operate within its various electric service areas but concluded that these rights only provided the opportunity to earn a regulated return and barriers to market entry, which in management's judgment is not considered a separately identifiable intangible asset under applicable accounting guidance; rather, it is considered going-concern value, or goodwill.

See Note 2, Acquisition by PPL and Note 7, Goodwill and Intangible Assets, for further information.

New Accounting Guidance

Recent accounting pronouncements affecting KU are detailed in Note 1, Summary of Significant Accounting Policies.

Other Information

PPL's Audit Committee has approved the audit fees and audit-related services. The audit-related services include services in connection with regulatory filings, reviews of offering documents and registration statements and internal control reviews.

Management's Report of Internal Controls Over Financial Reporting

Through December 31, 2010, the Company was not subject to the internal control and other requirements of the Sarbanes-Oxley Act of 2002 and associated rules (the "Act") and consequently is not required to evaluate the effectiveness of its internal control over financial reporting pursuant to Section 404 of the Act. However, management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process affected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework.* Management has concluded that, as of December 31, 2010, the Company's internal control over financial reporting was effective based on those criteria.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included herein.

Kentucky Utilities Company
Statements of Income
(millions)

	Successor	Predecessor		
	November 1 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31 2009	Year Ended December 31 2008
Operating revenues (Note 15)	$ 263	$ 1,248	$ 1,355	$ 1,405
Operating expenses:				
Fuel for electric generation	78	417	434	513
Power purchased (Notes 13 and 15)	28	147	199	221
Other operation and maintenance expenses	66	280	320	275
Depreciation and amortization	26	119	133	136
Total operating expenses	198	963	1,086	1,145
Operating income	65	285	269	260
Equity in earnings of unconsolidated venture (Note 1)	-	3	1	30
Interest expense (Notes 11 and 12)	8	6	6	14
Interest expense to affiliated companies (Notes 11, 12 and 15)	2	62	69	58
Other income (expense) - net	-	(2)	5	8
Income before income taxes	55	218	200	226
Income tax expense (Note 10)	20	78	67	68
Net income	$ 35	$ 140	$ 133	$ 158

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Retained Earnings
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Balance at beginning of period	$ 1,418	$ 1,328	$ 1,195	$ 1,037
Effect of PPL acquisition	(1,418)	-	-	-
Balance at November 1, 2010	-	1,328	1,195	1,037
Net income	35	140	133	158
Cash dividends declared (Note 15)	-	(50)	-	-
Balance at end of period	$ 35	$ 1,418	$ 1,328	$ 1,195

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Comprehensive Income
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Net income	$ 35	$ 140	$ 133	$ 158
Equity investee's other comprehensive loss, net of tax expense of $0, $1, $0 and $0, respectively (Note 1)	-	(2)	-	-
Comprehensive income	$ 35	$ 138	$ 133	$ 158

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets
(millions)

Assets	Successor December 31, 2010	Predecessor December 31, 2009
Current assets:		
Cash and cash equivalents	$ 3	$ 2
Accounts receivable (less allowance for doubtful accounts: 2010, $6; 2009, $3):		
Customer	90	79
Affiliated companies	12	9
Other	20	18
Unbilled revenues	89	76
Fuel, materials and supplies:		
Fuel (predominantly coal)	95	98
Other materials and supplies	41	39
Other intangible assets	22	-
Regulatory assets (Note 3)	9	32
Prepayments and other current assets	15	13
Total current assets	396	366
Investment in unconsolidated venture (Note 1)	30	12
Property, plant and equipment:		
Regulated utility plant – electric	3,630	4,892
Accumulated depreciation	(14)	(1,838)
Net regulated utility plant	3,616	3,054
Construction work in progress	955	1,257
Property, plant and equipment – net	4,571	4,311
Deferred debits and other assets:		
Regulatory assets (Notes 3 and 9):		
Pension benefits	117	105
Other regulatory assets	105	117
Goodwill (Notes 2 and 7)	607	-
Other intangibles assets (Notes 2 and 7)	175	-
Cash surrender value of key man life insurance	39	38
Other assets	19	7
Total deferred debits and other assets	1,062	267
Total assets	$ 6,059	$ 4,956

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (continued)
(millions)

Liabilities and Equity	Successor December 31, 2010	Predecessor December 31, 2009
Current liabilities:		
Current portion of long-term debt (Note 11)	$ -	$ 228
Current portion of long-term debt to affiliated company (Notes 11 and 15)	-	33
Notes payable to affiliated companies (Notes 12 and 15)	10	45
Accounts payable	67	107
Accounts payable to affiliated companies (Note 15)	45	88
Accrued taxes	25	14
Customer deposits	23	22
Regulatory liabilities (Note 3)	41	4
Accrued interest	8	1
Employee accruals	15	13
Other current liabilities	18	14
Total current liabilities	252	569
Long-term debt:		
Long-term bonds (Note 11)	1,841	123
Long-term debt to affiliated company (Notes 11 and 15)	-	1,298
Total long-term debt	1,841	1,421
Deferred credits and other liabilities:		
Deferred income taxes (Note 10)	376	336
Accumulated provision for pensions (Note 9)	113	160
Investment tax credits (Note 10)	104	104
Asset retirement obligations (Notes 3 and 4)	54	34
Regulatory liabilities (Note 3):		
Accumulated cost of removal of utility plant	348	335
Other regulatory liabilities	186	25
Other liabilities	94	20
Total deferred credits and other liabilities	$ 1,275	$ 1,014

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (continued)
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Equity:		
Common stock, without par value – authorized 80,000,000 shares, outstanding 37,817,878 shares	$ 308	$ 308
Additional paid-in capital	2,348	316
Retained earnings:		
Retained earnings	35	1,318
Undistributed earnings from unconsolidated venture	-	10
Total equity	2,691	1,952
Total liabilities and equity	$ 6,059	$ 4,956

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Cash flows from operating activities:				
Net income	$ 35	$ 140	$ 133	$ 158
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Depreciation and amortization	26	119	133	136
Deferred income taxes – net	4	23	50	(13)
Investment tax credits (Note 10)	-	-	24	25
Provision for pension and postretirement benefits	5	13	26	10
Other – net	2	(3)	-	1
Change in current assets and liabilities:				
Accounts receivable	(15)	13	11	13
Unbilled revenues	(32)	19	(15)	(1)
Fuel, materials and supplies	5	(6)	(28)	(33)
Regulatory assets	(2)	19	-	-
Other current assets	9	(9)	(3)	(1)
Accounts payable	9	(17)	(32)	2
Accounts payable to affiliated companies	(41)	46	29	7
Accrued taxes	15	(5)	6	8
Regulatory liabilities	12	3	-	-
Other current liabilities	(2)	2	2	(3)
Pension and postretirement funding (Note 9)	(2)	(18)	(20)	(5)
Storm restoration regulatory asset (Note 3)	-	-	(57)	(2)
Other regulatory assets	1	8	-	-
Other regulatory liabilities	-	(10)	-	-
Other – net	(1)	7	(6)	(10)
Net cash provided by (used in) operating activities	28	344	253	292
Cash flows from investing activities:				
Construction expenditures	(87)	(292)	(516)	(686)
Purchases of assets from affiliate	-	(48)	-	(10)
Change in restricted cash	-	-	9	1
Net cash provided by (used in) investing activities	$ (87)	$ (340)	$ (507)	$ (695)

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows (continued)
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010,	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Cash flows from financing activities:				
Issuance of bonds (Note 11)	$ 1,489	$ -	$ -	$ 77
Short-term borrowings from affiliated company – net (Note 12)	(83)	48	29	(7)
Other borrowings from affiliated companies (Note 11)	1,331	-	150	250
Repayments on other borrowings from affiliated companies (Note 11)	(1,331)	-	-	-
Repayments to E.ON affiliate (Note 11)	(1,331)	-	-	-
Debt issuance costs	(17)	-	-	-
Retirement of pollution control bonds	-	-	-	(60)
Acquisition of outstanding bonds	-	-	-	(80)
Reissuance of reacquired bonds	-	-	-	63
Retirement of reacquired bonds	-	-	-	17
Payment of dividends	-	(50)	-	-
Capital contribution (Note 15)	-	-	75	145
Net cash provided by (used in) financing activities	58	(2)	254	405
Change in cash and cash equivalents	(1)	2	-	2
Cash and cash equivalents at beginning of period	4	2	2	-
Cash and cash equivalents at end of period	$ 3	$ 4	$ 2	$ 2
Supplemental disclosures of cash flow information:				
Cash paid (received) during the year for:				
Interest – net of amount capitalized	$ 22	$ 62	$ 70	$ 66
Income taxes – net	(12)	74	(9)	46

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Long-term debt (Note 11):		
Pollution control series:		
Mercer Co. 2000 Series A, due May 1, 2023, variable %	$ 13	$ 13
Carroll Co. 2007 Series A, due February 1, 2026, 5.75%	18	18
Carroll Co. 2002 Series A, due February 1, 2032, variable %	21	21
Carroll Co. 2002 Series B, due February 1, 2032, variable %	2	2
Muhlenberg Co. 2002 Series A, due February 1, 2032, variable %	2	2
Mercer Co. 2002 Series A, due February 1, 2032, variable %	8	8
Carroll Co. 2008 Series A, due February 1, 2032, variable %	78	78
Carroll Co. 2002 Series C, due October 1, 2032, variable %	96	96
Carroll Co. 2006 Series B, due October 1, 2034, variable %	54	54
Trimble Co. 2007 Series A, due March 1, 2037, 6.0%	9	9
Carroll Co. 2004 Series A, due October 1, 2034, variable %	50	50
Total pollution control series	351	351
First mortgage bonds:		
First mortgage bond 2015 Series, due November 1, 2015, 1.625%	250	-
First mortgage bond 2020 Series, due November 1, 2020, 3.25%	500	-
First mortgage bond 2040 Series, due November 1, 2040, 5.125%	750	-
Total first mortgage bonds	$ 1,500	$ -

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization (continued)
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Long-term debt to affiliated company:		
Due November 24, 2010, 4.24%, unsecured	$ -	$ 33
Due January 16, 2012, 4.39%, unsecured	-	50
Due April 30, 2013, 4.55%, unsecured	-	100
Due August 15, 2013, 5.31%, unsecured	-	75
Due December 19, 2014, 5.45%, unsecured	-	100
Due July 8, 2015, 4.735%, unsecured	-	50
Due December 21, 2015, 5.36%, unsecured	-	75
Due October 25, 2016, 5.675%, unsecured	-	50
Due April 24, 2017, 5.28%, unsecured	-	50
Due June 20, 2017, 5.98%, unsecured	-	50
Due July 25, 2018, 6.16%, unsecured	-	50
Due August 27, 2018, 5.645%, unsecured	-	50
Due December 17, 2018, 7.035%, unsecured	-	75
Due July 29, 2019, 4.81%, unsecured	-	50
Due October 25, 2019, 5.71%, unsecured	-	70
Due November 25, 2019, 4.445%, unsecured	-	50
Due February 7, 2022, 5.69%, unsecured	-	53
Due May 22, 2023, 5.85%, unsecured	-	75
Due September 14, 2028, 5.96%, unsecured	-	100
Due June 23, 2036, 6.33%, unsecured	-	50
Due March 30, 2037, 5.86%, unsecured	-	75
Total long-term debt to affiliated company	-	1,331
Total long-term debt outstanding	1,851	1,682
Purchase accounting adjustments and discounts	(10)	-
Less current portion of long-term debt	-	261
Long-term debt	$ 1,841	$ 1,421

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization (continued)
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Common equity:		
Common stock, without par value – authorized 80,000,000 shares, outstanding 37,817,878 shares	$ 308	$ 308
Additional paid-in-capital	2,348	316
Retained earnings:		
Retained earnings	35	1,318
Undistributed subsidiary earnings	-	10
Total retained earnings	35	1,328
Total common equity	2,691	1,952
Total capitalization	$ 4,532	$ 3,373

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Notes to Financial Statements

Note 1 - Summary of Significant Accounting Policies

General

Terms and abbreviations are explained in the index of abbreviations. Dollars are in millions unless otherwise noted.

Business

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 514,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in five counties in southwestern Virginia and less than ten customers in Tennessee. KU's service area covers approximately 6,600 noncontiguous square miles. Approximately 98% of the electricity generated by KU is produced by its coal-fired electric generating stations. The remainder is generated by natural gas and oil fueled CTs and a hydroelectric power plant. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

On November 1, 2010, KU became an indirect wholly owned subsidiary of PPL, when PPL acquired all of the outstanding limited liability company interests in the Company's direct parent, LKE, from E.ON US Investments Corp. LKE, a Kentucky limited liability company, also owns the affiliate, LG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy and distribution and sale of natural gas in Kentucky. Following the acquisition, the Company's business has not changed. KU and LG&E are continuing as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies.

Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K.

Basis of Accounting

KU's basis of accounting incorporates the business combinations guidance of the FASB ASC as of the date of the acquisition, which requires the recognition and measurement of identifiable assets acquired and liabilities assumed at fair value as of the acquisition date. KU's financial statements and accompanying footnotes have been segregated to present pre-acquisition activity as the Predecessor and post-acquisition activity as the Successor. Predecessor covers the time period prior to November 1, 2010. Successor covers the time period after October 31, 2010. Certain accounting and presentation methods were changed to acceptable alternatives to conform to PPL accounting policies, which are discussed below, and the cost basis of certain assets and liabilities were changed as of November 1, 2010, as a result of the application of push-down accounting. Consequently, the financial position, results of operations and cash flows for the Predecessor period are not comparable to the Successor period.

Despite the separate presentation, the core operations of the Company have not changed. See Note 2, Acquisition by PPL, for information regarding the acquisition and the purchase accounting adjustments.

Changes in Classification

Certain reclassification entries have been made to the Predecessor's previous years' financial statements to conform to the 2010 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows. These reclassifications mainly consist of those necessary to identify amounts for prior periods that are separately disclosed in the financial statements.

Regulatory Accounting

KU is a cost-based rate-regulated utility. As a result, the financial statements reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise be charged to expense. Likewise, regulatory liabilities may be recognized for obligations expected to be returned through future regulated customer rates. The effect of such transactions or events would otherwise be reflected as income, or, in certain cases, regulatory liabilities are recorded based on the understanding with the regulator that current rates are being set to recover costs that are expected to be incurred in the future. The regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. Offsetting regulatory assets or liabilities for fair value purchase accounting adjustments have also been recorded to eliminate any ratemaking impact of the fair value adjustments. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC, Kentucky Commission, Virginia Commission or the Tennessee Regulatory Authority. See Note 3, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Management's Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported assets and liabilities, the disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Derivative Financial Instruments

KU enters into energy trading contracts to manage price risk and to maximize the value of power sales from the physical assets it owns. The energy trading contracts are non-hedging derivatives and the change in value is recognized in earnings on a mark-to-market basis. The Predecessor and Successor presentation are both appropriate under GAAP. The Predecessor and Successor determine the classification of energy trading contracts based on the settlement date of the individual contracts. Energy trading contracts classified as current are recognized in "Prepayments and other current assets" or "Other current liabilities" on the Balance Sheets. Energy trading contracts classified as non-current are recognized in "Other assets" or "Other liabilities" on the Balance Sheets. Cash inflows and outflows

related to derivative instruments are included as a component of operating activity on the Statements of Cash Flows, due to the underlying nature of the hedged items.

The Company does not net collateral against derivative instruments.

See Note 5, Derivative Financial Instruments, and Note 6, Fair Value Measurements, for further information on derivative instruments.

Revenue and Accounts Receivable

The operating revenues line item in the Statements of Income contains revenues from the following:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Residential	$ 106	$ 440	$ 480	$ 462
Industrial and commercial	117	588	637	636
Municipals	15	88	91	92
Other retail	20	114	118	108
Wholesale	5	18	29	107
	$ 263	$ 1,248	$ 1,355	$ 1,405

Revenue Recognition

Revenues are recorded based on service rendered to customers through month-end. Operating revenues are recorded based on energy deliveries through the end of the calendar month. Unbilled retail revenues result because customers' meters are read and bills are rendered throughout the month, rather than all being read at the end of the month. Unbilled revenues for a month are calculated by multiplying an estimate of unbilled kWh by the estimated average cents per kWh.

Accounts Receivable

Accounts receivable are reported in the Balance Sheets at the gross outstanding amount adjusted for an allowance for doubtful accounts.

Allowance for Doubtful Accounts

The allowance for doubtful accounts included in "Accounts receivable – customer" is based on the ratio of the amounts charged-off during the last twelve months to the retail revenues billed over the same period, multiplied by the retail revenues billed over the last four months. Accounts with no payment activity are charged-off after four months, although collection efforts continue thereafter. The allowance for doubtful accounts included in "Accounts receivable – other" is composed of accounts aged more than four months. Accounts are written off as management determines them uncollectible.

The changes in the allowance for doubtful accounts were:

	Successor	Predecessor		
	December 31, 2010	October 31, 2010	December 31, 2009	December 31, 2008
Balance at beginning of period (a)	$ -	$ 3	$ 3	$ 2
Charged to income	1	(6)	(4)	(2)
Charged to balance sheets	5	6	4	3
Balance at end of period	$ 6	$ 3	$ 3	$ 3

(a) Successor beginning of period reflects revaluation of accounts receivable due to purchase accounting.

Cash

Cash Equivalents

All highly liquid investments with an original maturity of three months or less are considered to be cash equivalents.

Restricted Cash

Bank deposits and other cash equivalents that are restricted by agreement or that have been clearly designated for a specific purpose are classified as restricted cash. The change in restricted cash is reported as an investing activity on the Statements of Cash Flows. On the Balance Sheets, restricted cash is included in “Prepayments and other current assets”. For KU, the December 31, 2010, balance of restricted cash was less than $1 million.

Fair Value Measurements

KU values certain financial assets and liabilities at fair value. Generally, the most significant fair value measurements relate to derivative assets and liabilities, investments in securities including investments in the pension and postretirement benefit plans and cash and cash equivalents. KU uses, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques) and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions that market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

KU prioritizes fair value measurements for disclosure by grouping them into one of three levels in the fair value hierarchy. The highest priority is given to measurements using level 1 inputs. The appropriate level assigned to a fair value measurement is based on the lowest level input that is significant to the fair value measurement in its entirety. The three levels of the fair value hierarchy are as follows:

- Level 1 - Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - Other inputs that are directly or indirectly observable in the marketplace.
- Level 3 - Unobservable inputs which are supported by little or no market activity.

Assessing the significance of a particular input requires judgment that considers factors specific to the asset or liability. As such, KU's assessment of the significance of a particular input may affect how the assets and liabilities are classified within the fair value hierarchy. See Note 5, Derivatives Financial Instruments, and Note 6, Fair Value Measurements, for further information on fair value measurements.

Investments

Equity Method Investment

KU's equity method investment, included in "Investment in unconsolidated venture" on the Balance Sheets, consists of its investment in EEI. KU owns 20% of the common stock of EEI, which owns and operates a 1,002 Mw summer capacity coal-fired plant and a 74 Mw summer capacity natural gas facility in southern Illinois. Through a power marketer affiliated with its majority owner, EEI sells its output to third parties. Although KU holds investment interest in EEI, it is not the primary beneficiary and is therefore not consolidated into the Company's financial statements. KU's investment in EEI is accounted for under the equity method of accounting and as of December 31, 2010 and 2009, totaled $30 million and $12 million, respectively. KU's direct exposure to loss as a result of its involvement with EEI is generally limited to the value of its investment. See Note 2, Acquisition by PPL, for further discussion regarding purchase accounting adjustments recognized for KU's investment in EEI.

The results of operations and financial position of EEI, KU's equity method investment, are summarized below.

Condensed income statement information for the years ended December 31 is as follows:

	2010 (unaudited)	2009	2008
Net sales	$ 343	$ 297	$ 514
Net income	16	10	142
KU's equity in earnings of EEI	3	1	30

Condensed balance sheet information as of December 31 is as follows:

	2010 (unaudited)	2009
Current assets	$ 62	$ 84
Long-lived assets	181	178
Total assets	$ 243	$ 262
Current liabilities	$ 113	$ 166
Long-term liabilities	72	50
Equity	58	46
Total liabilities and equity	$ 243	$ 262

Cost Method Investment

KU's cost method investment, included in "Investments in unconsolidated venture" on the Balance Sheets, consists of the Company's investment in OVEC. KU and 11 other electric utilities are owners of OVEC, which is located in Piketon, Ohio. OVEC owns and operates two coal-fired power plants, Kyger Creek Station in Ohio and Clifty Creek Station in Indiana with combined nameplate generating capacities of 2,390 Mw. OVEC's power is currently supplied to KU and 13 other companies affiliated with the various owners. Pursuant to current contractual agreements, KU owns 2.5% of OVEC's common stock and is contractually entitled to 2.5% of OVEC's output. Based on nameplate generating capacity, this would be approximately 60 Mw.

As of December 31, 2010 and 2009, KU's investment in OVEC totaled less than $1 million. KU is not the primary beneficiary of OVEC; therefore, it is not consolidated into the Company's financial statements and is accounted for under the cost method of accounting. The direct exposure to loss as a result of the Company's involvement with OVEC is generally limited to the value of its investment; however, KU may be conditionally responsible for a pro-rata share of certain OVEC obligations. See Note 2, Acquisition by PPL, and Note 13, Commitments and Contingencies, for further discussion regarding purchase accounting adjustments recognized, and KU's ownership interest and power purchase rights.

Long-Lived and Intangible Assets

Regulated Utility Plant

Regulated utility plant was stated at original cost for the Predecessor and adjusted to the net book value on November 1, 2010, the acquisition date, for the Successor. KU determined that fair value was equal to net book value at the acquisition date since KU's operations are conducted in a regulated environment. Original cost includes payroll-related costs such as taxes, fringe benefits and administrative and general costs. Construction work in progress has been included in the rate base for determining retail customer rates. KU has not recorded significant allowance for funds used during construction in accordance with FERC.

The cost of plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost is charged to the reserve for depreciation. When complete operating units are disposed of,

appropriate adjustments are made to the reserve for depreciation and gains and losses, if any, are recognized.

Capitalized Software Cost

Included in “Property, plant and equipment” on the Balance Sheets are capitalized costs of software projects that were developed or obtained for internal use. These capitalized costs are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Following are capitalized software costs and the accumulated amortization:

Successor		Predecessor	
December 31, 2010		December 31, 2009	
Carrying Amount	Accumulated Amortization (a)	Carrying Amount	Accumulated Amortization
$ 40	$ 1	$ 52	$ 13

(a) The accumulated amortization as of November 1, 2010, was netted against the carrying amount of the software as the fair value was determined to be equal to net book value for property, plant and equipment.

Amortization expense of capitalized software costs was as follows:

Successor	Predecessor		
		Year Ended December 31,	
November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	2009	2008
$ 1	$ 6	$ 6	$ 5

The amortization of capitalized software is included in “Depreciation and amortization” on the Statements of Income.

Depreciation and Amortization

Depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. The amounts provided as a percentage of depreciable plant were approximately:

Year	Percentage
2010	4.1%
2009	2.6%
2008	3.0%

Of the amount provided for depreciation, the following were related to the retirement, removal and disposal costs of long lived assets:

Year	Percentage
2010	0.6%
2009	0.4%
2008	0.5%

Goodwill, Intangible Assets and Asset Impairment

KU performs a quarterly review to determine if an impairment analyses is required for long-lived assets that are subject to depreciation or amortization. This review identifies changes in circumstances indicating that a long-lived asset's carrying value may not be recoverable. An impairment analysis will be performed if warranted, based on the review.

For a long-lived asset to be held and used, impairment exists when the carrying amount exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset is impaired, an impairment loss is recorded to adjust the asset's carrying amount to its fair value.

KU, as the result of PPL's acquisition of LKE, recorded the fair value of its coal contracts, emission allowances, EEI investment and OVEC power purchase contract. The difference between the fair value and the cost for these assets is being amortized over their useful lives based upon the pattern in which the economic benefits of the intangible assets are consumed or otherwise used. When determining the useful life of an intangible asset, including intangible assets that are renewed or extended, KU considers the expected use of the asset, the expected useful life of other assets to which the useful life of the intangible asset may relate and legal, regulatory, or contractual provisions that may limit the useful life. See Note 2, Acquisition by PPL, for methods used to determine the long-lived intangible assets' fair values. See Note 7, Goodwill and Intangible Assets, for the fair value amounts and amortization periods. The current intangible assets and long-term intangible assets are included in "Other intangible assets" on the Balance Sheets.

The Predecessor reported emission allowances in "Other materials and supplies" on the Balance Sheets. The emission allowances were not amortized; rather, they were expensed when consumed. The Predecessor did not recognize the coal contracts or the OVEC power purchase contract as these intangible assets were not derivatives.

In connection with PPL's acquisition of LKE, KU recorded goodwill on November 1, 2010. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is tested annually for impairment during the fourth quarter and more frequently if management determines that a triggering event may have occurred that would more likely than not reduce the fair value of an operating unit below its carrying value. Goodwill impairment charges are not subject to rate recovery. See Note 7, Goodwill and Intangible Assets, for further discussion regarding the Company's goodwill and current test results.

Asset Retirement Obligations

KU recognizes various legal obligations associated with the retirement of long-lived assets as liabilities in the financial statements. Initially this obligation is measured at fair value. An equivalent amount is recorded as an increase in the value of the capitalized asset and allocated to expense over the useful life of the asset. Until the obligation is settled, the liability is increased, through the recognition of accretion expense in the Statements of Income, for changes in the obligation due to the passage of time. An offsetting regulatory asset is recognized to reverse the depreciation and accretion expense related to the ARO such that there is no income statement impact. The regulatory asset is relieved when the ARO has been settled. Estimated ARO costs and settlement dates, which affect the carrying value of various AROs and the related assets, are reviewed periodically to ensure that any material changes are incorporated into the latest estimate of the obligations. See Note 4, Asset Retirement Obligations, for further information on AROs.

Defined Benefits

KU employees benefit from both funded and unfunded retirement benefit plans. An asset or liability is recorded to recognize the funded status of all defined benefit plans with an offsetting entry to regulatory assets or regulatory liabilities. Consequently, the funded status of all defined benefit plans is fully recognized on the Balance Sheets.

The expected return on plan assets is determined based on the current level of expected return on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class is then weighted based on the current asset allocation.

The discount rate used for pensions, postretirement and post-employment plans by the Predecessor was determined using the Mercer Yield Curve. The expected return on assets assumption was 7.75%. Gains and losses in excess of 10% of the greater of the plan's projected benefit obligation or market value of assets were amortized on a straight-line basis over the average future service period of active participants. The market-related value of assets was equal to the fair market value of the assets.

The discount rate used by the Successor was determined by the Towers Watson Yield Curve based on the individual plan cash flows. The expected return on assets was reduced from 7.75% to 7.25%. The amortization period for the recognition of gains and losses for retirement plans was changed to reflect the Successor's amortization policy. Under the Successor's method, gains and losses in excess of 10% but less than 30% of the greater of the plan's projected benefit obligation or market-related value of assets, are amortized on a straight-line basis over the average future service period of active participants. Gains and losses in excess of 30% of the plan's projected benefit obligation or market-related value of assets are amortized on a straight-line basis over a period equal to one-half of the average future service period of active participants. The market-related value of assets for the qualified retirement plans will be equal to a five year smoothed asset value. Gains and losses in excess of the expected return will be phased-in over a five-year period, prospectively from November 1, 2010.

See Note 9, Pension and Other Postretirement Benefit Plans, for further information.

Other

Loss Accruals

Potential losses are accrued when information is available that indicates it is “probable” that a loss has been incurred, given the likelihood of uncertain future events, and the amount of the loss can be reasonably estimated. Accounting guidance defines “probable” as cases in which “the future event or events are likely to occur.” KU continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events.

KU does not record the accrual of contingencies that might result in gains unless recovery is assured.

Income Taxes

For the periods ended on or before October 31, 2010, KU was a subsidiary of E.ON U.S. and was part of E.ON U.S.’s direct parent’s, E.ON US Investments Corp., consolidated U.S. federal income tax return. On November 1, 2010, KU became a part of PPL’s consolidated U.S. federal income tax return.

Significant management judgment is required in developing KU’s provision for income taxes primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and the determination of deferred tax assets, liabilities and valuation allowances.

KU evaluates tax positions following a two-step process. The first step requires an entity to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires an entity to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact the financial statements of KU.

Deferred income taxes reflect the net future tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes, as well as the tax effects of net operating losses and tax credit carryforwards.

KU records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. KU considers the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies in initially recording and subsequently reevaluating the need for valuation allowances. If KU determines that it is able to realize deferred tax assets in the future in excess of recorded net deferred tax assets, adjustments to the valuation allowances increase income by reducing tax expense in the period that such determination is made. Likewise, if KU determines that it is not able to realize all or part of net deferred tax assets in the future, adjustments to the valuation allowances would decrease income by increasing tax expense in the period that such determination is made.

The provision for KU's deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the regulators. The difference in the provision for deferred income taxes for regulated assets and liabilities and the amount that otherwise would be recorded under GAAP is deferred and included on the Balance Sheets in "Regulatory liabilities".

KU defers investment tax credits when the credits are utilized and amortizes the deferred amounts over the average lives of the related assets.

See Note 10, Income Taxes, for further discussion regarding income taxes.

Leases

KU evaluates whether arrangements entered into contain leases for accounting purposes.

Materials and Supplies

Fuel and other materials and supplies inventories are accounted for using the average-cost method.

Fuel Costs

The cost of fuel for electric generation is charged to expense as used. See Note 3, Rates and Regulatory Matters, for a description of the FAC.

Debt

The Company's long-term debt includes $228 million of pollution control bonds, which are subject to tender for purchase at the option of the holder and to mandatory tender for purchase on the occurrence of certain events. The Successor has classified these bonds as long term because the Company has the intent and ability to utilize its $400 million credit facility, which matures in December 2014, to fund any mandatory purchases. Predecessor classified these bonds as current portion of long-term debt due to the tender for purchase provisions. The Predecessor presentation and the Successor presentation are both appropriate under GAAP. See Note 11, Long-Term Debt, and Note 12, Notes Payable and Other Short-Term Obligations, for more information on the Company's debt and credit facilities.

Unamortized Debt Expense

Debt expense is capitalized and amortized over the lives of the related bond issues using the straight line method, which approximates the effective interest method. Depending on the type of expense, the Successor capitalized debt expenses in long-term other regulatory assets or long-term other assets to align with the term of the debt the expenses were related. The Predecessor capitalized debt expenses in current or long-term other regulatory assets or other current or long-term other assets based on the amount of expense expected to be recovered within the next year through rate recovery. Both the Predecessor and the Successor amortize debt expenses over the lives of the related bond issues. The Predecessor presentation and the Successor presentation are both appropriate under regulatory practices and GAAP.

Recent Accounting Pronouncements

The following recent accounting pronouncement affected KU:

Fair Value Measurements

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances and settlements within level 3 measurements. This guidance is effective for the interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about the roll-forward of activity in level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. This guidance has no impact on the Company's results of operations, financial position, liquidity or disclosures.

Note 2 - Acquisition by PPL

On November 1, 2010, PPL completed its acquisition of LKE and its subsidiaries. The push-down basis of accounting was used to record the fair value adjustments of assets and liabilities on LKE at the acquisition date. PPL paid a cash consideration for LKE and its subsidiaries of $2,493 million as well as a capital contribution on November 1, 2010, of $1,565 million; included within this was the consideration paid for KU of $2,656 million. The allocation of the KU purchase price was based on the fair value of assets acquired and liabilities assumed.

The allocation of the purchase price to the fair value of assets acquired and liabilities assumed is as follows:

Current assets	$	364
Investments		30
Property, plant and equipment		4,531
Other intangible assets		178
Regulatory and other non-current assets		274
Current liabilities (excluding current portion of long-term debt)		(367)
Affiliated debt		(1,331)
Debt (current and non-current)		(352)
Other non-current liabilities		(1,278)
Net identifiable assets acquired		2,049
Goodwill		607
Total purchase price	$	2,656

Goodwill represents value paid for the rate regulated business of KU, which is located in a defined service area with a constructive regulatory environment, which provides for future investment, earnings and cash flow growth, as well as the talented and experienced workforce. KU's franchise values are being attributed to the going concern value of the business, and thus were recorded as goodwill rather than a separately identifiable intangible asset. None of the goodwill recognized is deductible for income tax purposes or included in regulated customer rates.

Adjustments to KU's assets and liabilities that contributed to goodwill were as follows:

The fair value adjustment on the EEI investment was calculated using the discounted cash flow valuation method. The result was an increase in KU's value of the investment in EEI; the fair value of EEI was calculated to be $30 million and a fair value adjustment of $18 million was recorded on KU. The fair value adjustment to EEI is amortized over the expected remaining useful life of plant and equipment at EEI, which is estimated to be over 20 years.

The pollution control bonds on KU had a fair value adjustment of $1 million. All variable bonds were valued at par while the fixed rate bonds were valued with a yield curve based on average credit spreads for similar bonds.

As a result of the purchase accounting associated with the acquisition, the following items had a fair value adjustment but no effect on goodwill as the offset was either a regulatory asset or liability. The regulatory asset or liability has been recorded to eliminate any ratemaking impact of the fair value adjustments:

- The value of OVEC was determined to be $39 million based upon an announced transaction by another owner. KU's stock was valued at less than $1 million and the power purchase agreement has been valued at $39 million. An intangible asset was recorded with the offset to regulatory liability and will be amortized using the units of production method until the power purchase agreement ends in March 2026.
- KU recorded an emission allowance intangible asset and regulatory liability as the result of adjusting the fair value of the emission allowances at KU. The emission allowance intangible of $9 million represents allocated and purchased SO_2 and NOx emission allowances that are unused as of the valuation date or allocated for use in future years. KU had previously recorded emission allowances as other materials and supplies. To conform to PPL's accounting policy all emission allowances are now recorded as intangible assets. The emission allowance intangible asset is amortized as the emission allowances are consumed, which is expected to occur through 2040.
- KU recorded a coal contract intangible asset of $145 million and non-current liability of $22 million on the Balance Sheets. An offsetting regulatory asset was recorded for those contracts with unfavorable terms relative to market. An offsetting regulatory liability was recorded for those contracts that had favorable terms relative to market. All coal contracts held by KU, wherein it had entered into arrangements to buy amounts of coal at fixed prices from counterparties at a future date, were fair valued. The intangible assets and other liabilities, as well as the regulatory assets and liabilities, are being amortized over the same terms as the related contracts, which expire through 2016.

The fair value of intangible assets and liabilities (e.g. contracts that have favorable or unfavorable terms relative to market), including coal contracts and power purchase agreements, as well as emission allowances, have been reflected on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the acquisition. As a result, management believes the regulatory assets and liabilities created to offset the fair value adjustments meet the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair

value adjustments. KU's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU also considered whether a separate fair value should be assigned to KU's rights to operate within its various electric service areas but concluded that these rights only provided the opportunity to earn a regulated return and barriers to market entry, which in management's judgment is not considered a separately identifiable intangible asset under applicable accounting guidance; rather, it is considered going-concern value, or goodwill.

Note 3 - Rates and Regulatory Matters

The Company is subject to the jurisdiction of the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority in virtually all matters related to electric utility regulation and as such, its accounting is subject to the regulated operations guidance of the FASB ASC. Given its position in the marketplace and the status of regulation in Kentucky and Virginia, there are no plans or intentions to discontinue the application of the regulated operations guidance of the FASB ASC.

KU's Kentucky base rates are calculated based on a return on capitalization (common equity, long-term debt and notes payable) including certain regulatory adjustments to exclude non-regulated investments and environmental compliance plans recovered separately through the ECR mechanism. No regulatory assets or regulatory liabilities recorded at the time base rates were determined were excluded from the return on capitalization utilized in the calculation of Kentucky base rates. Therefore, a return is earned on all Kentucky regulatory assets existing at the time base rates were determined, except where such regulatory assets were offset by associated liabilities and thus, have no net impact on capitalization.

As a result of purchase accounting, certain fair value amounts, reflecting contracts that have favorable or unfavorable terms relative to market, were recorded on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered in customer rates the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. KU's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU's Virginia base rates are calculated based on a return on rate base. All regulatory assets and liabilities are excluded from the return on rate base utilized in the calculation of Virginia base rates.

KU's wholesale requirements rates for municipal customers are calculated based on annual updates to a rate formula that utilizes a return on rate base. All regulatory assets and liabilities are excluded from the return on rate base utilized in the development of municipal rates.

<u>2010 Purchase and Sale Agreement with PPL</u>

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments Corp., PPL and E.ON.

The transaction was subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals

(including the FERC and state regulators in Kentucky, Virginia and Tennessee) and the absence of injunctions or restraints imposed by governmental entities.

Change of control and financing-related applications were filed on May 28, 2010 with the Kentucky Commission and on June 15, 2010 with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings and data request filings and responses occurred. Early termination of the Hart-Scott-Rodino waiting period was received on August 2, 2010.

A hearing in the Kentucky Commission proceedings was held on September 8, 2010 at which time a unanimous settlement agreement was presented. In the settlement, KU committed that no base rate increases would take effect before January 1, 2013. The KU rate increases that took effect on August 1, 2010, were not impacted by the settlement. Under the terms of the settlement, KU retains the right to seek approval for the deferral of "extraordinary and uncontrollable costs." Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and demand-side management cost trackers. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Utilities file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits KU to earn up to a 10.75% return on equity. Any earnings above a 10.75% return on equity will be shared with customers on a 50%/50% basis. On September 30, 2010, the Kentucky Commission issued an Order approving the transfer of ownership of KU via the acquisition of E.ON U.S. by PPL, incorporating the terms of the submitted settlement. On October 19, 2010 and October 21, 2010, respectively, Orders approving the acquisition of E.ON U.S. by PPL were received from the Virginia Commission and the Tennessee Regulatory Authority. The Commissions' Orders contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In mid-September 2010, KU and other applicants in the FERC change of control proceeding reached an agreement with the protesters, whereby such protests have been withdrawn. The agreement, which was filed for consideration with the FERC, includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an agreement not to terminate certain KU municipal customer contracts prior to January 2017, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that KU has agreed not to seek the same transaction-related costs from retail customers and agreements to coordinate with protesters in certain open or ongoing matters. A FERC Order approving the transaction was received on October 26, 2010 and the transaction was completed November 1, 2010.

2010 Kentucky Rate Case

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $135 million annually. In June 2010, KU and all of the intervenors, except the AG, agreed to stipulations providing for an increase in electric base rates of $98 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulations, including a return on equity range of 9.75 – 10.75%. The new rates became effective on August 1, 2010.

Virginia Rate Case

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based on a return on equity of 12%. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing base rate revenue increases of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU refunded $1 million in interim rate amounts in excess of the ultimate approved rates.

FERC Wholesale Rate Case

In September 2008, KU filed an application with the FERC for increases in electric base rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from an all-in stated unit charge rate to an unbundled formula rate, including an annual adjustment mechanism. In 2009, the FERC issued an Order approving a settlement among the parties in the case, incorporating increases of approximately 3% from prior rates and a return on equity of 11%. In May 2010, KU submitted to the FERC the proposed current annual adjustments to the formula rates which incorporated certain proposed increases. Updated rates, including certain further adjustments from a review process involving wholesale requirements customers, became effective as of July 1, 2010, subject to certain review procedures by the wholesale requirements customers and the FERC.

By mutual agreement, the parties' settlement of the 2008 application left outstanding the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. An Order was issued by the FERC in July 2010, indicating that KU is not required to allocate a portion of any renewable resources to the twelve municipalities, thus resolving the remaining issue.

2008 Kentucky Rate Case

In July 2008, KU filed an application with the Kentucky Commission requesting an increase in electric base rates. In January 2009, KU, the AG, the KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which KU's electric base rates decreased by $9 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in the Balance Sheets as of December 31:

	Successor 2010	Predecessor 2009
Current regulatory assets:		
ECR (a)	$ -	$ 28
FAC (a)	-	1
Coal contracts (b)	4	-
MISO exit (c)	-	2
Other (d)	5	1
Total current regulatory assets	$ 9	$ 32
Non-current regulatory assets:		
Pension and postretirement benefits (e)	$ 117	$ 105
Other non-current regulatory assets:		
Storm restoration (c)	57	59
ARO (f)	2	30
Unamortized loss on bonds (c)	12	12
Coal contracts (b)	14	-
MISO exit (a)	5	9
Unamortized debt expense	5	-
Other (d)	10	7
Subtotal other non-current regulatory assets	105	117
Total non-current regulatory assets	$ 222	$ 222
Current regulatory liabilities:		
Coal contracts	$ 16	$ -
ECR	12	-
FAC	2	-
DSM	5	3
Emission allowances	6	-
Other (g)	-	1
Total current regulatory liabilities	$ 41	$ 4
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$ 348	$ 335
Other non-current regulatory liabilities:		
Coal contracts	126	-
OVEC power purchase contract	38	-
Deferred income taxes – net	6	9
Postretirement benefits	10	9
Other (g)	6	7
Subtotal other non-current regulatory liabilities	186	25
Total non-current regulatory liabilities	$ 534	$ 360

(a) The FAC and ECR regulatory assets have separate recovery mechanisms with recovery within twelve months.
(b) Offsetting regulatory asset for fair value purchase accounting adjustments. See Note 2, Acquisition by PPL, for information on the purchase accounting adjustments.
(c) These regulatory assets are recovered through base rates.
(d) Other regulatory assets include:
    - The CMRG and KCCS contributions, an EKPC FERC transmission settlement agreement and rate case expenses, which are recovered through base rates.
    - The FERC jurisdictional portion of the EKPC FERC transmission settlement agreement included in current and non-current regulatory assets, recovered through the application of the annual OATT formula rate updates.
    - FERC jurisdictional pension expense, which will be requested in a future FERC rate case.
    - Offsetting regulatory asset for fair value purchase accounting adjustment for leases. See Note 2, Acquisition by PPL, for information on the purchase accounting adjustments.
    - The Virginia levelized fuel factor, which is a separate recovery mechanism with recovery within twelve months.
(e) KU generally recovers this asset through pension expense included in the calculation of base rates.
(f) When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability.
(g) Other regulatory liabilities includes the emission allowance purchase accounting offset, MISO exit and a change in accounting method for FERC jurisdictional spare parts.

ECR

KU recovers the costs of complying with the Federal Clean Air Act pursuant to Kentucky Revised Statute 278-183 as amended and those federal, state or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal, through the ECR mechanism. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

The Kentucky Commission requires reviews of the past operations of the environmental surcharge for six-month and two-year billing periods to evaluate the related charges, credits and rates of return, as well as to provide for the roll-in of ECR amounts to base rates each two-year period. In December 2010, the Kentucky Commission initiated a six-month review of the Utilities' environmental surcharge for the billing period ending October 2010. An order is expected in the second quarter of 2011. Also, in December 2010, an Order was issued approving the charges and credits billed through the ECR during the six-month period ending April 2010, as well as approving billing adjustments for under-recovered costs and the rate of return on capital. In May 2010, an Order was issued approving the amounts billed through the ECR during the six-month period ending October 2009, and the rate of return on capital and allowing recovery of the under-recovery position in subsequent monthly filings. In December 2009, an Order was issued approving the charges and credits billed through the ECR during the two-year period ending April 2009, an increase in the jurisdictional revenue requirement, a base rate roll-in and a revised rate of return on capital. In July 2009, an Order was issued approving the charges and credits billed through the ECR during the six-month period ending October 2008, as well as approving billing adjustments for under-recovered costs and the rate of return on capital. In August 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month periods ending April

2008 and October 2007, and the rate of return on capital. In March 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month and two-year periods ending October 2006 and April 2007, respectively, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. During 2009, KU reached a unanimous settlement with all parties to the case and the Kentucky Commission issued an Order approving KU's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle. At December 31, 2009, the Company had a regulatory asset of $28 million, which changed to a regulatory liability in the first quarter of 2010, as a result of these roll-in adjustments to base rates. At December 31, 2010, the regulatory liability balance was $12 million.

In February 2009, the Kentucky Commission approved a settlement agreement in the rate case which provides for an authorized return on equity applicable to the ECR mechanism of 10.63% effective with the February 2009 expense month filing, which represents a slight increase over the previously authorized 10.50%. The 10.63% return on equity for the ECR mechanism was affirmed in the 2010 rate case.

FAC

KU's retail rates contain an FAC, whereby increases and decreases in the cost of fuel for generation are reflected in the rates charged to retail customers. The FAC allows the Company to adjust billed amounts for the difference between the fuel cost component of base rates and the actual fuel cost, including transportation costs. Refunds to customers occur if the actual costs are below the embedded cost component. Additional charges to customers occur if the actual costs exceed the embedded cost component. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

The Kentucky Commission requires public hearings at six-month intervals to examine past fuel adjustments and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges. In December 2010, May 2010, November 2009, January 2009, June 2008 and January 2008, the Kentucky Commission issued Orders approving the charges and credits billed through the FAC for the six-month periods ending April 2010, August 2009, April 2009, April 2008, October 2007 and April 2007, respectively. In January 2009 the Kentucky Commission initiated routine examinations of the FAC for the two-year periods November 1, 2006 through October 31, 2008. The Kentucky Commission issued an Order in June 2009 approving the charges and credits billed through the FAC during the review periods.

KU also employs an FAC mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The Virginia levelized fuel factor allows fuel recovery based on projected fuel costs for the coming year plus an adjustment for any over- or under-recovery of fuel expenses from the prior year. At December 31, 2010 and 2009, KU had a regulatory asset of $5 million and less than $1 million, respectively.

In February 2010, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor beginning with service rendered in April 2010. An Order was issued in April 2010, resulting in an agreed upon decrease of 23% from the fuel factor in effect for April 2009 through March 2010.

In February 2009, KU filed an application with the Virginia Commission seeking approval of a 29% increase in its fuel cost factor beginning with service rendered in April 2009. In February 2009, the Virginia Commission issued an Order allowing the requested change to become effective on an interim basis. The Virginia Staff testimony filed in April 2009 recommended a slight decrease in the factor filed by KU. The Company indicated the Virginia Staff proposal was acceptable. A hearing was held in May 2009, with general resolution of remaining issues. In May 2009, the Virginia Commission issued an Order approving the revised fuel factor, representing an increase of 24%, effective May 2009.

In February 2008, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor applicable during the billing period, April 2008 through March 2009. The Virginia Commission allowed the new rates to be in effect for the April 2008 customer billings. In April 2008, the Virginia Commission Staff recommended a change to the fuel factor KU filed in its application, to which KU agreed. Following a public hearing and an Order in May 2008, the recommended change became effective in June 2008, resulting in a decrease of 0.482 cents/kWh from the factor in effect for the April 2007 through March 2008 period.

Coal Contracts

In November 2010, purchase accounting adjustments were recorded for the fair value of KU’s coal contracts. Offsetting regulatory asset or liability for fair value purchase accounting adjustments eliminate any ratemaking impact of the fair value adjustments.

MISO

Following receipt of applicable FERC, Kentucky Commission and other regulatory Orders, related to proceedings that had been underway since July 2003, KU withdrew from the MISO effective September 1, 2006. Since the exit from the MISO, KU has been operating under a FERC approved OATT. KU now contracts with the TVA to act as its transmission reliability coordinator and SPP to function as its independent transmission operator, pursuant to FERC requirements. The contractual obligations with the TVA extend through August 2011 and with SPP through August 2012.

KU and the MISO agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, the Company paid $20 million to the MISO and made related FERC compliance filings. The Company’s payment of this exit fee was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. KU and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties’ recalculation of the exit fee and the approved agreement providing KU with recovery of $4 million, of which $1 million was immediately recovered in 2008, with the remainder to be recovered over the seven years from 2008 through 2014 for credits realized from other payments the MISO will receive, plus interest.

In accordance with Kentucky Commission Orders approving the MISO exit, KU established a regulatory asset for the MISO exit fee, net of former MISO administrative charges collected via base rates through the base rate case test year ended April 30, 2008. The net MISO exit fee is subject to adjustment for possible future MISO credits and a regulatory liability for certain revenues associated with former MISO administrative charges, which were collected via base rates until February 6, 2009. The approved 2008 base rate case settlement provided for MISO administrative charges collected through base rates from May 1, 2008 to February 6, 2009, and any future adjustments to the MISO exit fee, to be established as a regulatory liability until the amounts can be amortized in future base rate cases. This regulatory liability balance as of October 31, 2009, was included in the base rate case application filed on January 29, 2010. MISO exit fee credit amounts subsequent to October 31, 2009, will continue to accumulate as a regulatory liability until they can be amortized in future base rate cases.

In November 2008, the FERC issued Orders in industry-wide proceedings relating to MISO RSG calculation and resettlement procedures. RSG charges are amounts assessed to various participants active in the MISO trading market which generally seek to compensate for uneconomic generation dispatch due to regional transmission or power market operational considerations, with some customer classes eligible for payments, while others may bear charges. The FERC Orders approved two requests for significantly altered formulas and principles, each of which the FERC applied differently to calculate RSG charges for various historical and future periods. Based upon the 2008 FERC Orders, the Company established a reserve during the fourth quarter of 2008 of less than $1 million relating to potential RSG resettlement costs for the period ended December 31, 2008. However, in May 2009, after a portion of the resettlement payments had been made, the FERC issued an Order on the requests for rehearing on one November 2008 Order which changed the effective date and reduced almost all of the previously accrued RSG resettlement costs. Therefore, these costs were reversed and a receivable was established for amounts already paid of less than $1 million. The MISO began refunding the amounts to the Company in June 2009 with full repayment by September 2009. In June 2009, the FERC issued an Order in the rate mismatch RSG proceeding, stating it will not require resettlements of the rate mismatch calculation from April 1, 2005 to November 4, 2007. An accrual had previously been recorded in 2008 for the rate mismatch issue for the time period April 25, 2006 to August 9, 2007, but no accrual had been recorded for the time period November 5, 2007 to November 9, 2008 based on the prior Order. Accordingly, the accrual for the former time period was reversed and an accrual for the latter time period was recorded in June 2009, with a net effect of $1 million of expense, substantially all of which was paid by September 2009.

In August 2009, the FERC determined that the MISO had failed to demonstrate that its proposed exemptions to real-time RSG charges were just and reasonable. In November 2009, the MISO made a compliance filing incorporating the rulings of the FERC Orders and a related task force, with a primary open issue being whether certain of the tariff changes are applied prospectively only or retroactively to approximately January 6, 2009.

In November 2009, the Utilities filed an application with the FERC to approve certain independent transmission operator arrangements to be effective upon the expiration of their current contract with SPP in September 2010. The application sought authority for KU and LG&E to function after such date as the administrators of their own OATT for most purposes. However, due to the lack of FERC approval for such an approach and the approaching expiration of the SPP contract, the Utilities determined the approach was no longer reasonably achievable without unacceptable delay and uncertainty. In July 2010, the Utilities entered into a new agreement with SPP to provide independent transmission operator

services for a specified, limited time and removed its application for authority of administering its own OATT. The TVA, which currently acts as reliability coordinator, has also been retained under the existing service contract. The new agreement extends TVA services to August 2011 with no alterations or changes to the party's duties or responsibilities.

In August 2010, the FERC issued three Orders accepting most facets of several MISO RSG compliance filings. The FERC ordered the MISO to issue refunds for RSG charges that were imposed by the MISO on the assumption that there were rate mismatches for the period beginning November 5, 2007 through the present. There is no financial statement impact to the Company from this Order, as the MISO had anticipated that the FERC would require these refunds and had preemptively included them in the resettlements paid in 2009. The FERC denied the MISO's proposal to exempt certain resources from RSG charges, effective prospectively. The FERC accepted portions and rejected portions of the MISO's proposed RSG rate Redesign Proposal, which will be effective when the software is ready for implementation subject to further compliance filings. The impact of the Redesign Proposal on the Company cannot be estimated at this time.

Pension and Postretirement Benefits

KU accounts for pension and postretirement benefits in accordance with the compensation – retirement benefits guidance of the FASB ASC. This guidance requires employers to recognize the over-funded or under-funded status of a defined benefit pension and postretirement plan as an asset or liability on the Balance Sheets and to recognize through other comprehensive income the changes in the funded status in the year in which the changes occur. Under the regulated operations guidance of the FASB ASC, KU can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky and Virginia is based on the compensation – retirement benefits guidance of the FASB ASC. Regulators have been clear and consistent with their historical treatment of such rate recovery; therefore, the Company has recorded a regulatory asset representing the change in funded status of its pension plan that is expected to be recovered and a regulatory liability representing the change in funded status of its postretirement benefit plan. The regulatory asset and liability will be adjusted annually as prior service cost and actuarial gains and losses are recognized in net periodic benefit cost.

Storm Restoration

In January 2009, a significant ice storm passed through KU's service area causing approximately 199,000 customer outages, followed closely by a severe wind storm in February 2009, causing approximately 44,000 customer outages. An application was filed with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the establishment of a regulatory asset of up to $62 million based on actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, a regulatory asset of $57 million was established for actual costs incurred and approval was received in KU's 2010 base rate case to recover this asset over a ten year period beginning August 1, 2010.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service area causing significant outages and system damage. In October 2008, an application was filed with the

Kentucky Commission requesting approval to establish regulatory assets and defer for future recovery approximately $3 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the establishment a regulatory asset of up to $3 million based on actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, a regulatory asset of $2 million was established for actual costs incurred and KU received approval in its 2010 base rate case to recover this asset over a ten year period, beginning August 1, 2010.

Unamortized Loss on Bonds

The costs of early extinguishment of debt, including call premiums, legal and other expenses, and any unamortized balance of debt expense are amortized using the straight-line method, which approximates the effective interest method, over the life of either the replacement debt (in the case of refinancing) or the original life of the extinguished debt.

CMRG and KCCS Contributions

In July 2008, KU and LG&E, along with Duke Energy Kentucky, Inc. and Kentucky Power Company, filed an application with the Kentucky Commission requesting approval to establish regulatory assets related to contributions to the CMRG for the development of technologies for reducing carbon dioxide emissions and the KCCS to study the feasibility of geologic storage of carbon dioxide. The filing companies proposed that these contributions be treated as regulatory assets to be deferred until recovery is provided in the next base rate case of each company, at which time the regulatory assets will be amortized over the life of each project: four years with respect to the KCCS and ten years with respect to the CMRG. KU and LG&E jointly agreed to provide $2 million over two years to the KCCS and up to $2 million over ten years to the CMRG. In October 2008, an Order approving the establishment of the requested regulatory assets was received. KU received approval from the Kentucky Commission in the Company’s 2010 Kentucky base rate case to recover these regulatory assets over the requested period beginning August 1, 2010.

Rate Case Expenses

KU incurred $1 million in expenses related to the development and support of the 2008 Kentucky base rate case. The Kentucky Commission approved the establishment of a regulatory asset for these expenses and authorized amortization over three years beginning in March 2009.

KU incurred $2 million in expenses related to the development and support of the 2010 Kentucky base rate case. The Kentucky Commission approved the establishment of a regulatory asset for these expenses and authorized amortization over three years beginning in August 2010.

FERC Jurisdictional Pension Costs

Other regulatory assets include pension costs of $5 million incurred by the Company and allocated to its FERC jurisdictional ratepayers. The Company will seek recovery of this asset in the next FERC rate proceeding.

Deferred Storm Costs

Based on an Order from the Kentucky Commission in June 2004, KU reclassified from maintenance expense to a regulatory asset $4 million related to costs not reimbursed from the 2003 ice storm. These costs were amortized through June 2009. KU earned a return of these amortized costs, which were included in jurisdictional operating expenses.

DSM

DSM consists of energy efficiency programs which are intended to reduce peak demand and delay the investment in additional power plant construction, provide customers with tools and information to become better managers of their energy usage and prepare for potential future legislation governing energy efficiency. KU's rates contain a DSM provision which includes a rate mechanism that provides for concurrent recovery of DSM costs and provides an incentive for implementing DSM programs. The provision allows KU to recover revenues from lost sales associated with the DSM programs based on program plan engineering estimates and post-implementation evaluations.

In July 2007, KU and LG&E filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. KU and LG&E filed revised tariffs in April 2008, under authority of this Order, which were effective in May 2008.

Emission Allowances

In November 2010, purchase accounting adjustments were recorded for the fair market value of KU's SO_2, NOx ozone season and NOx annual emission allowances. Offsetting regulatory assets or liabilities for fair value purchase accounting adjustments eliminate any ratemaking impact of the fair value adjustments. KU is granted SO_2 emission allowances through 2040 and NOx ozone season and NOx annual emission allowances through 2011.

Accumulated Cost of Removal of Utility Plant

As of December 31, 2010 and 2009, KU segregated the cost of removal, previously embedded in accumulated depreciation, of $348 million and $335 million, respectively, in accordance with FERC Order No. 631. For reporting purposes on the Balance Sheets, KU presented this cost of removal as a "Regulatory liability" pursuant to the regulated operations guidance of the FASB ASC.

OVEC Power Purchase Contract

In November 2010, purchase accounting adjustments were recorded for the fair value of the power purchase agreement between KU and OVEC. Offsetting regulatory liability for fair value purchase accounting adjustment eliminate any ratemaking impact of the fair value adjustments.

Deferred Income Taxes – Net

These regulatory liabilities represent the future revenue impact from the reversal of deferred income taxes required for unamortized investment tax credits, the allowance for funds used during construction and deferred taxes provided at rates in excess of currently enacted rates.

<u>Other Regulatory Matters</u>

Kentucky Commission Report on Storms

In November 2009, the Kentucky Commission issued a report following review and analysis of the effects and utility response to the September 2008 wind storm and the January 2009 ice storm and possible utility industry preventative measures relating thereto. The report suggested a number of proposed or recommended preventative or responsive measures, including consideration of selective hardening of facilities, altered vegetation management programs, enhanced customer outage communications and similar measures. In March 2010, the Utilities filed a joint response reporting on their actions with respect to such recommendations. The response indicated implementation or completion of substantially all of the recommendations, including, among other matters, on-going reviews of system hardening and vegetation management procedures, certain test or pilot programs in such areas and fielding of enhanced operational and customer outage-related systems.

Wind Power Agreements

In August 2009, KU and LG&E filed a notice of intent with the Kentucky Commission indicating their intent to file an application for approval of wind power purchase contracts and cost recovery mechanisms. The contracts were executed in August 2009 and were contingent upon KU and LG&E receiving acceptable regulatory approvals. Pursuant to the proposed 20-year contracts, KU and LG&E would jointly purchase respective assigned portions of the output of two Illinois wind farms totaling an aggregate 109.5 Mw. In September 2009, the Utilities filed an application and supporting testimony with the Kentucky Commission. In October 2009, the Kentucky Commission issued an Order denying the Utilities' request to establish a surcharge for recovery of the costs of purchasing wind power. The Kentucky Commission stated that such recovery constitutes a general rate adjustment and is subject to the regulations of a base rate case. The Kentucky Commission Order provided for the request for approval of the wind power agreements to proceed independently from the request to recover the costs thereof via surcharges. In November 2009, KU and LG&E filed for rehearing of the Kentucky Commission's Order and requested that the matters of approval of the contract and recovery of the costs thereof remain the subject of the same proceeding. During December 2009, the Kentucky Commission issued data requests on this matter. In March 2010, the Utilities delivered notices of termination under provisions of the wind power contracts. The Utilities also filed a motion with the Kentucky Commission noting the termination of the contracts and seeking withdrawal of their application in the related regulatory proceeding. In April 2010, the Kentucky Commission issued an Order allowing the Utilities to withdraw their pending application.

Trimble County Asset Purchase and Depreciation

In July 2009, the Utilities notified the Kentucky Commission of the proposed sale from the Utilities of certain ownership interests in certain existing Trimble County generating station assets which were

anticipated to provide joint or common use in support of the jointly-owned TC2 generating unit under construction at the station. The undivided ownership interests sold provide KU an ownership interest in these common assets proportional to its interest in TC2 and the assets' role in supporting both TC1 and TC2. In December 2009, the Utilities completed the sale transaction at a price of $48 million, representing the current net book value of the assets multiplied by the proportional interest being sold.

In August 2009, the Utilities jointly filed an application with the Kentucky Commission to approve new depreciation rates for applicable jointly-owned TC2-related generating, pollution control and other plant equipment and assets. During December 2009, the Kentucky Commission extended the data discovery process through January 2010 and authorized the Utilities on an interim basis to begin using the depreciation rates for TC2 as proposed in the application. In March 2010, the Kentucky Commission issued a final Order approving the use of the proposed depreciation rates on a permanent basis.

TC2 CCN Application and Transmission Matters

An application for a CCN for construction of TC2 was approved by the Kentucky Commission in November 2005. CCNs for two transmission lines associated with TC2 were issued by the Kentucky Commission in September 2005 and May 2006. All regulatory approvals and rights of way for one transmission line have been obtained.

KU's and LG&E's CCN for a transmission line associated with the TC2 construction has been challenged by certain property owners in Hardin County, Kentucky. Certain proceedings relating to CCN challenging and federal historic preservation permit requirements have concluded with outcomes in the Utilities' favor.

Completion of the transmission lines are also subject to standard construction permit, environmental authorization and real property or easement acquisition procedures. Certain Hardin County landowners have raised challenges to the transmission line in some of these forums as well.

With respect to the remaining on-going dispute, KU obtained various successful rulings during 2008 at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals and received a temporary stay preventing KU from accessing their properties. In May 2010, the Kentucky Court of Appeals issued an Order affirming the Hardin Circuit Court's finding that KU had the right to condemn easements on the properties. In May 2010, the landowners filed a petition for reconsideration with the Court of Appeals. In July 2010, the Court of Appeals denied that petition. In August, 2010, the landowners filed for discretionary review of that denial by the Kentucky Supreme Court.

Settlement discussions with the Hardin County property owners involved in the appeals of the condemnation proceedings have been unsuccessful to date. During the fourth quarter of 2008, KU and LG&E entered into settlements with certain Meade County landowners and obtained dismissals of prior litigation they brought challenging the same transmission line.

As a result of the aforementioned unresolved litigation delays encountered in obtaining access to certain properties in Hardin County, KU obtained easements to allow construction of temporary transmission facilities, bypassing those properties while the litigated issues are resolved. In September 2009, the Kentucky Commission issued an Order stating that a CCN was necessary for two segments of the

proposed temporary facilities. In December 2009, the Kentucky Commission granted the CCNs for the relevant segments and the property owners have filed various motions to intervene, stay and appeal certain elements of the Kentucky Commission's recent orders. In January 2010, in respect of two of such proceedings, the Franklin County circuit court issued Orders denying the property owners' request for a stay of construction and upholding the prior Kentucky Commission denial of their intervenor status.

Consistent with the regulatory authorizations and the favorable outcome of the legal proceedings, the Utilities completed construction activities on the permanent transmission line easements. During 2010, the Utilities placed the transmission line into operation. While the Utilities are not currently able to predict the ultimate outcome and possible financial effects of the remaining legal proceedings, the Utilities do not believe the matter involves relevant or continuing risks to operations.

Utility Competition in Virginia

The Commonwealth of Virginia passed the Virginia Electric Utility Restructuring Act in 1999. This act gave customers the ability to choose their electric supplier and capped electric rates through December 2010. KU subsequently received a legislative exemption from the customer choice requirements of this law. In April 2007, however, the Virginia General Assembly amended the Virginia Electric Utility Restructuring Act, thereby terminating this competitive market and commencing re-regulation of utility rates. The new act ended the cap on rates at the end of 2008. Pursuant to this legislation, the Virginia Commission adopted regulations revising the rules governing utility rate increase applications. As of January 2009, a hybrid model of regulation is being applied in Virginia. Under this model, utility rates are reviewed every two years. KU's exemption from the requirements of the Virginia Electric Utility Restructuring Act in 1999, however, discharges the Company from the requirements of the new hybrid model of regulation. In lieu of submitting an annual information filing, the Company has the option of requesting a change in base rates to recover prudently incurred costs by filing a traditional base rate case. KU is also subject to other utility regulations in Virginia, including, but not limited to, the recovery of prudently incurred fuel costs through an annual fuel factor charge and the submission of integrated resource plans.

Market-Based Rate Authority

In July 2006, the FERC issued an Order in KU's market-based rate proceeding accepting the Company's further proposal to address certain market power issues the FERC claimed would arise upon an exit from the MISO. In particular, the Company received permission to sell power at market-based rates at the interface of balancing areas in which it may be deemed to have market power, subject to a restriction that such power will not be collusively re-sold back into such balancing areas. However, restrictions exist on sales by KU of power at market-based rates in the KU and LG&E and Big Rivers Electric Company balancing areas. In June 2007, the FERC issued Order No. 697 implementing certain reforms to market-based rate regulations, including restrictions similar to those previously in place for the Company's power sales at balancing area interfaces. In December 2008, the FERC issued Order No. 697-B potentially placing additional restrictions on certain power sales involving areas where market power is deemed to exist. As a condition of receiving and retaining market-based rate authority, KU must comply with applicable affiliate restrictions set forth in the FERC regulation. During September 2008, the Company submitted a regular triennial update filing under market-based rate regulations.

In June 2009, the FERC issued Order No. 697-C which generally clarified certain interpretations relating to power sales and purchases at balancing area interfaces or into balancing areas involving market power. In July 2009, the FERC issued an Order approving the Company's September 2008 application for market-based rate authority. During July 2009, affiliates of KU completed a transaction terminating certain prior generation and power marketing activities in the Big Rivers Electric Company balancing area, which termination should ultimately allow a filing to request a determination that the Company no longer is deemed to have market power in such balancing area.

KU conducts certain of its wholesale power sales activities in accordance with existing market-based rate authority principles and interpretations. Future FERC proceedings relating to Orders 697 or market-based rate authority could alter the amount of sales made at market-based versus cost-based rates. The Company's sales under market-based rate authority totaled less than $1 million for the year ended December 31, 2010.

Mandatory Reliability Standards

As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007 and authority was delegated to various Regional Reliability Organizations ("RROs") by the NERC, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. The Utilities are members of the SERC, which acts as KU's and LG&E's RRO. During December 2009 and April, July and August 2010, the Utilities submitted ten self-reports relating to various standards, which self-reports remain in the early stages of RRO review, and therefore, the Utilities are unable to estimate the outcome of these matters. Mandatory reliability standard settlements commonly also include non-penalty elements, including compliance steps and mitigation plans. Settlements with SERC proceed to NERC and FERC review before becoming final. While the Utilities believe they are in compliance with the mandatory reliability standards, events of potential non-compliance may be identified from time-to-time. The Utilities cannot predict such potential violations or the outcome of self-reports described above.

Integrated Resource Planning

Integrated resource planning ("IRP") regulations in Kentucky require major utilities to make triennial IRP filings with the Kentucky Commission. In April 2008, KU and LG&E filed their 2008 joint IRP with the Kentucky Commission. The IRP provides historical and projected demand, resource and financial data and other operating performance and system information. The Kentucky Commission issued a staff report and Order closing this proceeding in December 2009. Pursuant to the Virginia Commission's December 2008 Order, KU filed its IRP in July 2009. The filing consisted of the 2008 Joint IRP filed by KU and LG&E with the Kentucky Commission along with additional data. The Virginia Commission has not established a procedural schedule for this proceeding. KU expects to file their next IRP in April 2011.

PUHCA 2005

PPL, KU's ultimate parent, is a holding company under PUHCA 2005. PPL, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries, are subject to extensive regulation by the FERC

with respect to numerous matters, including electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. KU believes that it has adequate authority, including financing authority, under existing FERC Orders and regulations to conduct its business and will seek additional authorization when necessary.

EPAct 2005

The EPAct 2005 was enacted in August 2005. Among other matters, this comprehensive legislation contains provisions mandating improved electric reliability standards and performance; granting enhanced civil penalty authority to the FERC; providing economic and other incentives relating to transmission, pollution control and renewable generation assets; increasing funding for clean coal generation incentives; repealing the Public Utility Holding Company Act of 1935; enacting PUHCA 2005; and expanding FERC jurisdiction over public utility holding companies and related matters via the Federal Power Act and PUHCA 2005.

In February 2006, the Kentucky Commission initiated an administrative proceeding to consider the requirements of the EPAct 2005, Subtitle E Section 1252, Smart Metering, which concerns time-based metering and demand response, and Section 1254, Interconnections. EPAct 2005 requires each state regulatory authority to conduct a formal investigation and issue a decision on whether or not it is appropriate to implement certain Section 1252 standards within eighteen months after the enactment of EPAct 2005 and to commence consideration of Section 1254 standards within one year after the enactment of EPAct 2005. Following a public hearing with all Kentucky jurisdictional electric utilities, in December 2006, the Kentucky Commission issued an Order in this proceeding indicating that the EPAct 2005 Section 1252 and Section 1254 standards should not be adopted. However, all five Kentucky Commission jurisdictional utilities were required to file real-time pricing pilot programs for their large commercial and industrial customers. KU developed a real-time pricing pilot program for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by KU for implementation within approximately eight months. The tariff was filed in October 2008, with an effective date of December 1, 2008. KU files annual reports on the program within 90 days of each plan year end for the three-year pilot period.

Green Energy Riders

In February 2007, KU and LG&E filed a Joint Application and Testimony for Proposed Green Energy Riders. In May 2007, a Kentucky Commission Order was issued authorizing KU to establish Small and Large Green Energy Riders, allowing customers to contribute funds to be used for the purchase of renewable energy credits. During November 2009, KU and LG&E filed an application to both continue and modify the existing Green Energy Programs. In February 2010, the Kentucky Commission approved the Utilities' application, as filed.

Home Energy Assistance Program

In July 2007, KU filed an application with the Kentucky Commission for the establishment of a Home Energy Assistance program. During September 2007, the Kentucky Commission approved the five-year

program as filed, effective in October 2007. The programs were scheduled to terminate in September 2012 and is funded through a $0.10 per month meter charge. Effective February 6, 2009, as a result of the settlement agreement in the 2008 base rate case, the program is funded through a $0.15 per month meter charge. As a condition in the settlement in the change of control proceeding before the Kentucky Commission in the PPL acquisition, the program was extended to September 2015.

Collection Cycle Revision

As part of its base rate case filed on July 29, 2008, LG&E proposed to change the due date for customer bill payments from 15 days to 10 days to align its collection cycle with KU. In addition, in its rate case filed on July 29, 2008, KU proposed to include a late payment charge if payment is not received within 15 days from the bill issuance date to align with LG&E. The settlement agreements approved in the rate cases in February 2009 changed the due date for customer bill payments to 12 days after bill issuance for both KU and LG&E and permitted KU's implementation of a late payment charge if payment is not received within 15 days from the bill issuance date.

Depreciation Study

In December 2007, KU filed a depreciation study with the Kentucky Commission as required by a previous Order. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding. The approved settlement agreements in the rate cases established new depreciation rates effective February 2009. KU also filed the depreciation study with the Virginia Commission which approved the implementation of the new depreciation rates effective February 2009. Approval by the Virginia Commission does not preclude the rates from being raised as an issue by any party in KU's future base rate cases in Virginia.

Brownfield Development Rider Tariff

In March 2008, KU received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a Brownfield site, as certified by the appropriate Kentucky state agency. The rider permits special contracts with such customers which provide for a series of declining partial rate discounts over an initial five-year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant Brownfield sites.

Interconnection and Net Metering Guidelines

In May 2008, the Kentucky Commission on its own motion initiated a proceeding to establish interconnection and net metering guidelines in accordance with amendments to existing statutory requirements for net metering of electricity. The jurisdictional electric utilities and intervenors in this case presented proposed interconnection guidelines to the Kentucky Commission in October 2008. In a January 2009 Order, the Kentucky Commission issued the Interconnection and Net Metering Guidelines – Kentucky that were developed by all parties to the proceeding. KU does not expect any financial or other impact as a result of this Order. In April 2009, KU filed revised net metering tariffs and application forms pursuant to the Kentucky Commission's Order. The Kentucky Commission issued an Order in April 2009, which suspended for five months all net metering tariffs filed by the jurisdictional

electric utilities. This suspension was intended to allow sufficient time for review of the filed tariffs by the Kentucky Commission Staff and intervening parties. In June 2009, the Kentucky Commission Staff held an informal conference with the parties to discuss issues related to the net metering tariffs filed by KU. Following this conference, the intervenors and KU resolved all issues and KU filed revised net metering tariffs with the Kentucky Commission. In August 2009, the Kentucky Commission issued an Order approving the revised tariffs.

EISA 2007 Standards

In November 2008, the Kentucky Commission initiated an administrative proceeding to consider new standards as a result of the Energy Independence and Security Act of 2007 ("EISA 2007"), part of which amends the Public Utility Regulatory Policies Act of 1978 ("PURPA"). There are four new PURPA standards and one non-PURPA standard applicable to electric utilities. The proceeding also considers two new PURPA standards applicable to natural gas utilities. EISA 2007 requires state regulatory commissions and non-regulated utilities to begin consideration of the rate design and smart grid investments no later than December 19, 2008 and to complete the consideration by December 19, 2009. The Kentucky Commission established a procedural schedule that allowed for data discovery and testimony through July 2009. In October 2009, the Kentucky Commission held an informal conference for the purpose of discussing issues related to the standard regarding the consideration of Smart Grid investments. A public hearing has not been scheduled in this matter.

Note 4 - Asset Retirement Obligations

A summary of KU's net ARO assets, ARO liabilities and regulatory assets established under the asset retirement and environmental obligations guidance of the FASB ASC follows:

	ARO Net Assets	ARO Liabilities	Regulatory Assets
As of December 31, 2008, Predecessor	$ 5	$ (32)	$ 28
ARO accretion and depreciation	(1)	(2)	2
As of December 31, 2009, Predecessor	4	(34)	30
ARO accretion and depreciation	-	(2)	2
Reclassification for retired assets	(1)	-	1
ARO revaluation - change in estimates	22	(24)	2
As of October 31, 2010, Predecessor	25	(60)	35
ARO accretion and depreciation	(1)	-	1
Purchase accounting - fair value adjustment	28	6	(34)
As of December 31, 2010, Successor	$ 52	$ (54)	$ 2

In September 2010, the Company performed a revaluation of its AROs as a result of recently proposed environmental legislation and improved ability to forecast asset retirement costs due to recent construction and retirement activity.

In November 2010, the Company recorded a purchase accounting adjustment to fair value AROs due to the PPL acquisition.

Pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC, an offsetting regulatory credit was recorded in "Depreciation and amortization" in the Statements of Income for the Successor of $1 million in 2010 and $2 million for the Predecessor for the ARO accretion and depreciation expense. The offsetting regulatory credit recorded was $2 million in 2009 and 2008 for the ARO accretion and depreciation expense. The ARO liabilities are offset by cash settlements that have not yet been applied. Therefore, ARO net assets, ARO liabilities and regulatory assets balances do not net to zero due to the cash settlements.

KU's AROs are primarily related to the final retirement of assets associated with generating units. KU transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under the asset retirement and environmental obligations guidance of the FASB ASC, no material asset retirement obligations are recorded for transmission and distribution assets.

Note 5 – Derivative Financial Instruments

KU is subject to interest rate and commodity price risk related to on-going business operations. The Company's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. Although the Company's policies allow for the use of interest rate swaps, as of December 31, 2010 and 2009, KU had no interest rate swaps outstanding. At December 31, 2010, KU's potential annual exposure to increased interest expense, based on a 10% increase in interest rates, was less than $1 million.

The Company does not net collateral against derivative instruments.

Energy Trading and Risk Management Activities

KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to manage price risk and are accounted for as non-hedging derivatives on a mark-to-market basis in accordance with the derivatives and hedging guidance of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from Intercontinental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity data is unavailable, other inputs include prices quoted by brokers or observable inputs other than quoted prices, such as one-sided bids or offers as of the balance sheet date. Quotes are verified quarterly using an independent pricing source of actual transactions. Quotes for combined off-peak and weekend timeframes are allocated between the two timeframes based on their historical proportional ratios to the integrated cost. No other adjustments are made to the forward prices. No changes to valuation techniques for energy trading and risk management activities occurred during 2010 or 2009. Changes in market pricing, interest rate and volatility assumptions were made during both years.

KU's financial assets and liabilities as of December 31, 2010 and December 31, 2009, arising from energy trading and risk management contracts not designated as hedging instruments accounted for at fair value total less than $1 million and are recorded in prepayments and other current assets and other current liabilities, respectively.

The Company maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, KU seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. The Company uses ratings of S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, KU assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At December 31, 2010, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. The Company has reserved against counterparty credit risk based on KU's own creditworthiness (for net liabilities) and its counterparty's creditworthiness (for net assets). The Company applies historical default rates within varying credit ratings over time provided by S&P or Moody's. At December 31, 2010 and December 31, 2009, counterparty credit reserves related to energy trading and risk management contracts were less than $1 million.

The net volume of electricity based financial derivatives outstanding at December 31, 2010 and December 31, 2009, was 129,199 Mwh and 315,600 Mwh, respectively. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2010 and December 31, 2009. Cash collateral related to the energy trading and risk management contracts is recorded in "Prepayments and other current assets" on the Balance Sheets.

KU manages the price risk of its estimated future excess economic generation capacity using market-traded forward contracts. Hedge accounting treatment has not been elected for these transactions; therefore, realized and unrealized gains and losses are included in the Statements of Income.

The following table presents the effect of market-traded forward contract derivatives not designated as hedging instruments on income:

		Successor	Predecessor		
Loss Recognized in Income	Location	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Unrealized gain (loss)	Electric revenues	$ -	$ -	$ (1)	$ 1

Net realized gains and losses were zero for the period ended December 31, 2010 and less than $1 million for the periods ended October 31, 2010, December 31, 2009 and December 31, 2008.

Credit Risk Related Contingent Features

Certain of KU's derivative contracts contain credit contingent provisions which would permit the counterparties with which KU is in a net liability position to require the transfer of additional collateral upon a decrease in KU's credit rating. Some of these provisions would require KU to transfer additional collateral or permit the counterparty to terminate the contract if KU's credit rating were to fall below investment grade. Some of these provisions also allow the counterparty to require additional collateral upon each decrease in the credit rating at levels that remain above investment grade. In either case, if KU's credit rating were to fall below investment grade (i.e., below BBB- for S&P or Baa3 for Moody's), and assuming no assignment to an investment grade affiliate were allowed, most of these credit contingent provisions require either immediate payment of the net liability as a termination payment or immediate and ongoing full collateralization by KU on derivative instruments in net liability positions.

Additionally, certain of KU's derivative contracts contain credit contingent provisions that require KU to provide "adequate assurance" of performance if the other party has reasonable grounds for insecurity regarding KU's performance of its obligation under the contract. A counterparty demanding adequate assurance could require a transfer of additional collateral or other security, including letters of credit, cash and guarantees from a creditworthy entity. A demand for additional assurance would typically involve negotiations among the parties.

To determine net liability positions, KU uses the fair value of each agreement. At December 31, 2010, there were no energy trading and risk management derivative contracts with credit risk related contingent features that are in a liability position and collateral of less than $1 million was posted in the normal course of business. At December 31, 2010, a downgrade of the Company's credit rating below investment grade would have no effect on the energy trading and risk management derivative contracts or collateral required.

Note 6 - Fair Value Measurements

KU adopted the fair value guidance in the FASB ASC in two phases. Effective January 1, 2008, the Company adopted it for all financial instruments and non-financial instruments accounted for at fair value on a recurring basis, and effective January 1, 2009, the Company adopted it for all non-financial instruments accounted for at fair value on a non-recurring basis. The FASB ASC guidance clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. As a basis for considering such assumptions, the FASB ASC guidance establishes a three-tier value hierarchy, which prioritizes the inputs used in the valuation methodologies in measuring fair value.

The carrying values and estimated fair values of KU’s non-trading financial instruments follow:

	Successor December 31, 2010		Predecessor December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term bonds	$ 1,841	$ 1,728	$ 351	$ 351
Long-term debt to affiliated company	-	-	1,331	1,401

The long-term fixed rate pollution control bond valuations reflect prices quoted by investment banks, which are active in the market for these instruments. First mortgage bond valuations reflect prices quoted from a third party service. The fair value of the long-term debt due to affiliated company is determined using an internal valuation model that discounts the future cash flows of each loan at current market rates as determined based on quotes from investment banks that are actively involved in capital markets for utilities and factor in KU’s credit ratings and default risk. The fair values of cash and cash equivalents, accounts receivable, cash surrender value of key man life insurance, accounts payable and notes payable are substantially the same as their carrying values.

KU has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures guidance of the FASB ASC, as discussed in Note 1, Summary of Significant Accounting Policies.

The Company classifies its derivative cash collateral balances within level 1 based on the funds being held in a demand deposit account. The Company classifies its derivative energy trading and risk management contracts within level 2 because it values them using prices actively quoted for proposed or executed transactions, quoted by brokers or observable inputs other than quoted prices.

KU’s financial assets and liabilities as of December 31, 2010 and 2009, arising from energy trading and risk management contracts accounted for at fair value on a recurring basis total less than $1 million. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2010 and December 31, 2009 each year.

There were no level 3 measurements for the periods ending December 31, 2010 and December 31, 2009.

Note 7 - Goodwill and Intangible Assets

In connection with PPL’s acquisition of LKE, KU recorded goodwill on November 1, 2010. In addition, as of November 1, 2010, certain intangible assets were adjusted to their fair value and new intangible assets were recorded. See Note 2, Acquisition by PPL, for further information.

Goodwill

The Company performs its required annual goodwill impairment test in the fourth quarter. Impairment tests are performed between the annual tests when the Company determines that a triggering event has occurred that would, more likely than not, reduce the fair value of a reporting unit below its carrying value. The goodwill impairment test is comprised of a two-step process. In step 1, the Company identifies a potential impairment by comparing the estimated fair value of the regulated utilities (the

goodwill reporting unit) to their carrying value, including goodwill, on the measurement date. If the estimated fair value exceeds its carrying amount, goodwill is not considered impaired. If the fair value is less than the carrying value, then step 2 is performed to measure the amount of impairment loss, if any. The step 2 calculation compares the implied fair value of the goodwill to the carrying value of the goodwill. The implied fair value of goodwill is equal to the excess of the Company estimated fair value over the fair values of its identified assets and liabilities. If the carrying value of goodwill exceeds the implied fair value of goodwill, an impairment loss is recognized in an amount equal to that excess (but not in excess of the carrying value).

In connection with PPL's acquisition of LKE on November 1, 2010, goodwill of $607 million was recorded on November 1, 2010. The allocation of the goodwill to KU was based on the net asset value of the Company. The goodwill represents value paid for the rate regulated business located in a defined service area with a constructive regulatory environment, which provides for future investment, earnings and cash flow growth, as well as the talented and experienced workforce. KU's franchise values are being attributed to the going concern value of the business and thus were recorded as goodwill rather than a separately identifiable intangible asset. None of the goodwill recognized is expected to be deductible for income tax purposes or included in customer rates. See Note 2, Acquisition by PPL, for further information.

For the 2010 annual impairment test, the primary valuation technique used was an income methodology based on management's estimates of forecasted cash flows for the Company, with those cash flows discounted to present value using rates commensurate with the risks of those cash flows. Management also took into consideration the acquisition price paid by PPL. The discounted cash flows for the Company was based on discrete financial forecasts developed by management for planning purposes and consistent with those given to PPL. Cash flows beyond the discrete forecasts were estimated using a terminal-value calculation, which incorporated historical and forecasted financial trends for the Company. No impairment resulted from the fourth quarter test, as the determined fair value of the Company was greater than its carrying value.

Other Intangible Assets

The gross carrying amount and the accumulated amortization of other intangible assets were as follows:

	Successor	
	December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:		
Coal contracts (a)	$ 145	$ 3
Land rights (b)	8	-
Emission allowances (c)	9	-
OVEC power purchase agreement (d)	39	1
Total other intangible assets	$ 201	$ 4

(a) The gross carrying amount represents the fair value of coal contracts recognized as a result of the 2010 acquisition by PPL. The weighted average amortization period of these contracts is 3 years. See Note 2, Acquisition by PPL, for further information.

(b) The gross carrying amount represents the fair value of land rights recognized as a result of adopting PPL's accounting policies in the Successor period. The weighted average amortization period of these rights is 17 years. See Note 1, Summary of Significant Accounting Policies, for further information.

(c) The gross carrying amount represents the fair value of emission allowances recognized as a result of the 2010 acquisition by PPL, as well as the reclassification of amounts from inventory to intangible assets as a result of adopting PPL's accounting policies in the Successor period. The weighted average amortization period of these emission allowances is 3 years. See Note 2, Acquisition by PPL, for further information.

(d) The gross carrying amount represents the fair value of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. The weighted average amortization period of the power purchase agreement is 8 years. See Note 2, Acquisition by PPL, for further information.

Current intangible assets and long-term intangible assets are included in "Other intangible assets" in their respective areas on the Balance Sheets in 2010. Intangible assets resulting from purchase accounting adjustments are not recoverable in rates.

Amortization expense, excluding consumption of emission allowances, was $4 million for the Successor in 2010. The estimated aggregate amortization expense for each of the next five years is as follows:

	Estimated Expense in Period Ended				
	2011	2012	2013	2014	2015
Aggregate amortization expense	$ 43	$ 25	$ 27	$ 24	$ 26

Note 8 - Concentrations of Credit and Other Risk

Credit risk represents the accounting loss that would be recognized at the reporting date if counterparties failed to perform as contracted. Concentrations of credit risk (whether on- or off-balance sheet) relate to groups of customers or counterparties that have similar economic or industry characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

All of KU's customer receivables arise from deliveries of electricity. During 2010, the Company's ten largest customers accounted for less than 19% of volumes.

Effective August 4, 2009, KU and its employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement. The agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. KU and its employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement in August 2008. This agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. The employees represented by these two bargaining units comprise approximately 15% of the Company's workforce at December 31, 2010.

Note 9 - Pension and Other Postretirement Benefit Plans

KU employees benefit from both funded and unfunded retirement benefit plans. Its defined benefit pension plan covers employees hired by December 31, 2005. Employees hired after this date participate in the Retirement Income Account ("RIA"), a defined contribution plan. The postretirement plan includes health care benefits that are contributory, with participants' contributions adjusted annually. The Company uses December 31 as the measurement date for its plans.

Obligations and Funded Status

The following tables provide a reconciliation of the changes in the defined benefit plans' obligations, the fair value of assets and the funded status of the plans for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 355	$ 316	$ 306	$ 84	$ 80	$ 75
Service cost	1	5	6	-	1	2
Interest cost	3	16	18	1	4	4
Benefits paid, net of retiree contributions	(3)	(14)	(18)	(1)	(4)	(5)
Actuarial (gain) loss and other	(2)	32	4	(1)	3	4
Benefit obligation at end of period	$ 354	$ 355	$ 316	$ 83	$ 84	$ 80

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 237	$ 219	$ 183	$ 20	$ 17	$ 12
Actual return on plan assets	7	20	41	-	1	3
Employer contributions	-	13	13	2	6	7
Benefits paid, net of retiree contributions	(3)	(14)	(18)	(1)	(4)	(5)
Administrative expenses and other	-	(1)	-	-	-	-
Fair value of plan assets at end of period	$ 241	$ 237	$ 219	$ 21	$ 20	$ 17
Funded status at end of period	$ (113)	$ (118)	$ (97)	$ (62)	$ (64)	$ (63)

Amounts Recognized in the Balance Sheets

The following tables provide the amounts recognized in the Balance Sheets and information for plans with benefit obligations in excess of plan assets plans for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Regulatory assets	$ 117	$ 125	$ 105	$ -	$ -	$ -
Regulatory liabilities	-	-	-	(10)	(9)	(9)
Accrued benefit liability (non-current)	(113)	(118)	(97)	(62)	(64)	(63)

Amounts recognized in regulatory assets and liabilities for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Transition obligation	$ -	$ -	$ -	$ 2	$ 2	$ 3
Prior service cost	3	4	5	1	1	2
Accumulated loss (gain)	114	121	100	(13)	(12)	(14)
Total regulatory assets and liabilities	$ 117	$ 125	$ 105	$ (10)	$ (9)	$ (9)

Additional information for plans with accumulated benefit obligations in excess of plan assets for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Benefit obligation	$ 354	$ 355	$ 316	$ 83	$ 84	$ 80
Accumulated benefit obligation	299	299	268	-	-	-
Fair value of plan assets	241	237	219	21	20	17

The amounts recognized in regulatory assets and liabilities for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Net (gain) loss arising during the period	$ (6)	$ 26	$ (22)	$ (1)	$ 2	$ 2
Amortization of prior service cost	-	(1)	(1)	-	-	-
Amortization of transitional obligation	-	-	-	-	(2)	(1)
Amortization of loss	(2)	(5)	(9)	-	-	-
Total amounts recognized in regulatory assets and liabilities	$ (8)	$ 20	$ (32)	$ (1)	$ -	$ 1

For discussion of the pension and postretirement regulatory assets, see Note 3, Rates and Regulatory Matters.

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost for pension and other postretirement benefit plans. The tables include the costs associated with both KU employees and Servco employees who provide services to KU. The Servco costs are allocated to KU based on employees' labor charges and are approximately 51%, 49% and 46% of Servco's costs for 2010, 2009 and 2008, respectively.

	Pension Benefits					
	Successor			Predecessor		
	November 1, 2010 through December 31, 2010			January 1, 2010 through October 31, 2010		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 1	$ 1	$ 2	$ 5	$ 5	$ 10
Interest cost	3	2	5	16	6	22
Expected return on plan assets	(3)	(1)	(4)	(14)	(5)	(19)
Amortization of prior service cost	-	-	-	1	1	2
Amortization of actuarial gain	2	-	2	5	2	7
Net periodic benefit cost	$ 3	$ 2	$ 5	$ 13	$ 9	$ 22

	Pension Benefits					
	Predecessor - Year Ended December 31, 2009			Predecessor - Year Ended December 31, 2008		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 6	$ 5	$ 11	$ 6	$ 4	$ 10
Interest cost	18	7	25	18	6	24
Expected return on plan assets	(15)	(4)	(19)	(21)	(5)	(26)
Amortization of prior service cost	1	1	2	1	1	2
Amortization of actuarial gain	9	2	11	-	-	-
Net periodic benefit cost	$ 19	$ 11	$ 30	$ 4	$ 6	$ 10

	Other Postretirement Benefits					
	Successor			Predecessor		
	November 1, 2010 through December 31, 2010			January 1, 2010 through October 31, 2010		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ -	$ -	$ -	$ 1	$ 1	$ 2
Interest cost	1	-	1	4	-	4
Expected return on plan assets	-	-	-	(1)	-	(1)
Amortization of transition obligation	-	-	-	1	-	1
Net periodic benefit cost	$ 1	$ -	$ 1	$ 5	$ 1	$ 6

	Other Postretirement Benefits					
	Predecessor - Year Ended December 31, 2009			Predecessor Year Ended December 31, 2008		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	5	-	5	5	-	5
Expected return on plan assets	(1)	-	(1)	(1)	-	(1)
Amortization of transition obligation	1	-	1	1	-	1
Net periodic benefit cost	$ 6	$ 1	$ 7	$ 6	$ 1	$ 7

The estimated amounts that will be amortized from regulatory assets and liabilities into net periodic benefit cost in 2011 are shown in the following table:

	Pension Benefits	Other Postretirement Benefits
Regulatory assets and liabilities:		
Net actuarial loss	$ 8	$ -
Prior service cost	1	1
Transition obligation	-	1
Total regulatory assets and liabilities amortized during 2011	$ 9	$ 2

The weighted average assumptions used in the measurement of KU's pension and postretirement benefit obligations for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor are shown in the following table:

	Successor	Predecessor	
	December 31, 2010	October 31, 2010	December 31, 2009
Discount rate – pension benefits	5.52%	5.46%	6.13%
Discount rate – postretirement benefits	5.12%	4.96%	5.82%
Rate of compensation increase	5.25%	5.25%	5.25%

For the first ten months of 2010, the discount rates used to determine the pension and postretirement benefit obligations and the period expense were determined using the Mercer Pension Discount Yield Curve. This model takes the plans' cash flows and matches them to a yield curve that provides the equivalent yields on zero-coupon corporate bonds for each maturity. The discount rate is the single rate

that produces the same present value of cash flows. The selection of the various discount rates represents the equivalent single rate under a broad-market AA yield curve constructed by Mercer.

For the last two months of 2010, the Towers Watson Yield Curve was used to determine the discount rate. This model also starts with an analysis of the expected benefit payment stream for its plans. This information is first matched against a spot-rate yield curve. A portfolio of Aa-graded non-callable (or callable with make-whole provisions) bonds, with a total amount outstanding in excess of $667 billion, serves as the base from which those with the lowest and highest yields are eliminated to develop the ultimate yield curve. The results of this analysis are considered together with other economic data and movements in various bond indices to determine the discount rate assumption.

The weighted average assumptions used in the measurement of KU's pension and postretirement net periodic benefit costs for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor are shown in the following table:

	Successor	Predecessor		
	2010	2010	2009	2008
Discount rate - pension	5.45%	5.46%	6.25%	6.66%
Discount rate - postretirement	4.94%	5.82%	6.36%	6.56%
Expected long-term return on plan assets	7.25%	7.75%	8.25%	8.25%
Rate of compensation increase	5.25%	5.25%	5.25%	5.25%

To develop the expected long-term rate of return on assets assumption, KU considered the current level of expected returns on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the current asset allocation to develop the expected long-term rate of return on assets assumption for the portfolio. The Company has determined that the 2011 expected long-term rate of return on assets assumption should be 7.25%.

The following describes the effects on pension benefits by changing the major actuarial assumptions discussed above:

- A 1% change in the assumed discount rate would have a $39 million positive or negative impact to the 2010 accumulated benefit obligation and an approximate $51 million positive or negative impact to the 2010 projected benefit obligation.
- A 25 basis point change in the expected rate of return on assets would have resulted in less than a $1 million positive or negative impact to 2010 pension expense.
- A 25 basis point increase in the rate of compensation increase would have a $3 million negative impact to the 2010 projected benefit obligation.

Assumed Health Care Cost Trend Rates

For measurement purposes, an 8% annual increase in the per capita cost of covered health care benefits was assumed for the first ten months of 2010. The rate was assumed to decrease gradually to 4.5% by 2029 and remain at that level thereafter. For the last two months of 2010, an 8% annual increase in the

per capita cost of covered health care benefits was assumed and the rate was assumed to decrease gradually to 5.5% by 2019. For 2011, a 9% annual increase in the per capita cost of covered health care benefits is assumed and the rate is assumed to decrease gradually to 5.5% by 2019. This change in the length of the health care trend was made to conform to PPL's accounting policies.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in assumed health care cost trend rates would have resulted in an increase or decrease of less than $1 million to the 2010 total of service and interest costs components and an increase or decrease of $4 million in year end 2010 postretirement benefit obligations.

Expected Future Benefit Payments and Medicare Subsidy Receipts

The following list provides the amount of expected future benefit payments, which reflect expected future service costs and the estimated gross amount of Medicare subsidy receipts:

	Pension Benefits	Other Postretirement Benefits	Medicare Subsidy Receipts
2011	$ 18	$ 6	$ 1
2012	18	6	-
2013	18	6	1
2014	18	7	-
2015	18	7	1
2016-2020	106	36	3

Plan Assets

The following table shows the pension plan's weighted average asset allocation by asset category at December 31:

	Target Range	Successor 2010	Predecessor 2009
Equity securities	45% - 75%	56%	59%
Debt securities	30% - 50%	24%	40%
Other	0% - 10%	20%	1%
Totals		100%	100%

The investment policy of the pension plans was developed in conjunction with financial and actuarial consultants, investment advisors and legal counsel. The goal of the investment policy is to preserve the capital of the pension plans' assets and maximize investment earnings in excess of inflation with acceptable levels of volatility. The return objective is to exceed the benchmark return for the policy index comprised of the following: Russell 3000 Index, MSCI-EAFE Index, Barclays Capital Aggregate and Barclays Capital U.S. Long Government/Credit Bond Index in proportions equal to the targeted asset allocation.

Evaluation of performance focuses on a long-term investment time horizon over rolling three and five-year periods. The assets of the pension plans are broadly diversified within different asset classes (equities, fixed income securities and cash equivalents).

To minimize the risk of large losses in a single asset class, no more than 5% of the portfolio will be invested in the securities of any one issuer with the exclusion of the U.S. government and its agencies. The equity portion of the fund is diversified among the market's various subsections to diversify risk, maximize returns and avoid undue exposure to any single economic sector, industry group or individual security. The equity subsectors include, but are not limited to, growth, value, small capitalization and international.

In addition, the overall fixed income portfolio may have an average weighted duration, or interest rate sensitivity which is within +/- 20% of the duration of the overall fixed income benchmark. Foreign bonds in the aggregate shall not exceed 10% of the total fund. The portfolio may include a limited investment of up to 20% in below investment grade securities provided that the overall average portfolio quality remains "AA" or better. The below investment grade securities include, but are not limited to, medium-term notes, corporate debt, non-dollar and emerging market debt and asset backed securities. The cash investments should be in securities that are either short maturities (not to exceed 180 days) or readily marketable with modest risk.

Derivative securities are permitted only to improve the portfolio's risk/return profile, to modify the portfolio's duration or to reduce transaction costs and must be used in conjunction with underlying physical assets in the portfolio. Derivative securities that involve speculation, leverage, interest rate anticipation, or any undue risk whatsoever are not deemed appropriate investments.

The investment objective for the postretirement benefit plan is to provide current income consistent with stability of principal and liquidity while maintaining a stable net asset value of $1.00 per share. The postretirement funds are invested in a prime cash money market fund that invests primarily in a portfolio of short-term, high-quality fixed income securities issued by banks, corporations and the U.S. government.

KU has classified plan assets that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures guidance of the FASB ASC. See Note 6, Fair Value Measurements, for further information.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs.

A description of the valuation methodologies used to measure plan assets at fair value is provided below:

> *Money market funds*: These investments are public investment vehicles valued using $1 for the net asset value. The money market funds are classified within level 2 of the valuation hierarchy.
>
> *Common/collective trusts:* Valued based on the beginning of year value of the plan's interests in the trust plus actual contributions and allocated investment income (loss) less actual distributions and allocated administrative expenses. Quoted market prices are used to value investments in the trust, with the exception of the GAC. The fair value of certain other investments for which quoted market prices are not available are valued based on yields currently available on

comparable securities of issuers with similar credit ratings. The common/collective trusts are classified within level 2 of the valuation hierarchy.

The preceding methods described may produce a fair value that may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

Prior to the acquisition, the GAC was considered an immediate participation guarantee contract which was not included in the fair value table. In accordance with the plan accounting guidance of the FASB ASC, the cost incurred to purchase the GAC prior to March 20, 1992, was permitted to be carried at contract value, since it is a contract with an insurance company and prior to the acquisition it was excluded from the table above. The cost incurred to fund the GAC after March 20, 1992, was carried at contract value in accordance with the plan accounting guidance of the FASB ASC, since it was a contract that incorporates mortality and morbidity risk. Contract value represents cost plus interest income less distributions for benefits and administrative expenses. To conform to PPL's accounting methods, the John Hancock GAC was classified in the fair value table as a level 3 and as "other" rather than "debt securities" in the asset allocation table for the period ended December 31, 2010.

The following table sets forth, by level within the fair value hierarchy, the plan's assets at fair value at December 31:

	Successor		Predecessor	
	Level 2	Level 3	Level 2	Level 3
Money market funds	$ 2	$ -	$ 2	$ -
Common/collective trusts	213	-	186	-
John Hancock - GAC	-	47	-	-
Total investments at fair value	$ 215	$ 47	$ 188	$ -

The following table sets forth a reconciliation of changes in the fair value of the plan's level 3 assets for the following period:

	Successor
Balance at November 1, 2010	$ -
Purchases	1
Transfers into level 3	46
Balance at December 31, 2010	$ 47

There are no assets categorized as level 1 as of December 31, 2010 and December 31, 2009.

Contributions

KU made discretionary contributions to the pension plan of $13 million in 2010 and 2009. Servco made $9 million and $8 million in discretionary contributions to its pension plan in 2010 and 2009, respectively. The amount of future contributions to the pension plan will depend upon the actual return on plan assets and other factors, but the Company funds its pension obligations in a manner consistent

with the Pension Protection Act of 2006. The Company made contributions totaling $43 million in January 2011.See Note 18, Subsequent Events, for further information.

The Company made contributions to its other postretirement benefit plan of $8 million in 2010 and $7 million in 2009. In 2011, the Company anticipates making voluntary contributions to fund Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Pension Legislation

The Pension Protection Act of 2006 was enacted in August 2006. New rules regarding funding of defined benefit plans are generally effective for plan years beginning in 2008. Among other matters, this comprehensive legislation contains provisions applicable to defined benefit plans which generally (i) mandate full funding of current liabilities within seven years; (ii) increase tax-deduction levels regarding contributions; (iii) revise certain actuarial assumptions, such as mortality tables and discount rates; and (iv) raise federal insurance premiums and other fees for under-funded and distressed plans. The legislation also contains a number of provisions relating to defined-contribution plans and qualified and non-qualified executive pension plans and other matters. The Company's plan met the minimum funding requirements as defined by the Pension Protection Act of 2006 for years ended December 31, 2010 and 2009.

Thrift Savings Plans

KU has a thrift savings plan under section 401(k) of the Internal Revenue Code. Under the plan, eligible employees may defer and contribute to the plan a portion of current compensation in order to provide future retirement benefits. KU makes contributions to the plan by matching a portion of the employees' contributions. The costs of this matching were $3 million in 2010, 2009 and 2008.

KU also makes contributions to RIAs within the thrift savings plans for certain employees not covered by the non-contributory defined benefit pension plan. These employees consist of those hired after December 31, 2005. The Company makes these contributions based on years of service and the employees' wage and salary levels, and makes them in addition to the matching contributions discussed above. The amounts contributed by the Company under this arrangement were less than $1 million in 2010, 2009 and 2008.

Health Care Reform

In March 2010, Health Care Reform (the Patient Protection and Affordable Care Act of 2010) was signed into law. Many provisions of Health Care Reform do not take effect for an extended period of time and many aspects of the law which are currently unclear or undefined will likely be clarified in future regulations.

During 2010, KU recorded an income tax expense of less than $1 million to recognize the impact of the elimination of the tax deduction related to the Medicare Retiree Drug Subsidy that becomes effective in 2013.

Specific provisions within Health Care Reform that may impact KU include:

- Beginning in 2011, requirements extend dependent coverage up to age 26, remove the $2 million lifetime maximum and eliminate cost sharing for certain preventative care procedures.
- Beginning in 2018, a potential excise tax is expected on high-cost plans providing health coverage that exceeds certain thresholds.

The Company has evaluated these provisions of Health Care Reform on its benefit programs in consultation with its actuarial consultants and has determined that the excise tax will not have an impact on its postretirement medical plans. The requirement to extend dependent coverage up to age 26 is not expected to have a significant impact on active or retiree medical costs. The Company will continue to monitor the potential impact of any changes to the existing provisions and implementation guidance related to Health Care Reform on its benefit programs.

Note 10 - Income Taxes

KU's federal income tax return is included in a United States consolidated income tax return filed by LKE's direct parent. Prior to October 31, 2010 the return was included in the consolidated return of E.ON US Investments Corp. Due to the acquisition by PPL, the return will be included in the consolidated PPL return beginning November 1, 2010, for each tax period. Each subsidiary of the consolidated tax group, including KU, calculates its separate income tax for each period. The resulting separate-return tax cost or benefit is paid to or received from the parent company or its designee. The Company also files income tax returns in various state jurisdictions. While 2007 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2007-2008 have been received from the IRS, effectively closing these years to additional audit adjustments. Tax years beginning with 2007 were examined under an IRS program, Compliance Assurance Process ("CAP"). This program accelerates the IRS's review to begin during the year applicable to the return and ends 90 days after the return is filed. KU had no adjustments for the 2007 federal tax return. For 2008, the IRS allowed additional deductions in connection with the Company's application for a change in repair deductions and disallowed certain bonus depreciation claimed on the original return. The net temporary tax impact for the Company was a $12 million reduction in tax and was recorded in the second quarter of 2010. The 2009 federal return was filed in the third quarter of 2010 and the IRS issued a Partial Acceptance Letter in connection with CAP. The IRS is continuing to review bonus depreciation, storms and other repairs. No net material adverse impact is expected from these remaining areas. The short tax year beginning January 1, 2010 through October 31, 2010, is also being examined under CAP. No material items have been raised by the IRS at this time. The two month period beginning November 1, 2010 and ending December 31, 2010 is not currently under examination.

Additions and reductions of uncertain tax positions during 2010, 2009 and 2008 were less than $1 million. Possible amounts of uncertain tax positions for KU that may decrease within the next 12 months total less than $1 million and are based on the expiration of the audit periods as defined in the statutes. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

The amount KU recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million for the twelve month periods ended and as of December 31, 2010, 2009 and 2008. The interest expense and interest accrued is based on IRS and Kentucky Department of Revenue

large corporate interest rates for underpayment of taxes. At the date of adoption, the Company accrued less than $1 million in interest expense on uncertain tax positions. KU records the interest as "Interest expense" and penalties, if any, as "Operating expenses" on the Statements of Income and "Other current liabilities" on the Balance Sheets, on a pre-tax basis. No penalties were accrued by the Company through December 31, 2010.

Components of income tax expense are shown in the table below:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Current:				
Federal	$ 13	$ 46	$ (5)	$ 46
State	3	9	1	10
Deferred:				
Federal – net	4	20	43	(10)
State – net	-	3	7	(3)
Investment tax credit – deferred	-	-	21	25
Total income tax expense	$ 20	$ 78	$ 67	$ 68

In June 2006, KU and LG&E filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for an investment tax credit applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that KU and LG&E were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, KU received an Order from the Kentucky Commission approving the accounting of the investment tax credit, which includes a full depreciation basis adjustment for the amount of the credit. KU's portion of the TC2 tax credit is approximately $101 million. Based on eligible construction expenditures incurred, KU recorded an investment tax credit of $21 million and $25 million in 2009 and 2008, respectively, decreasing current federal income taxes. As of December 31, 2009, KU had recorded its maximum credit of $101 million. The income tax expense impact from amortizing this credit over the life of the related property began when the facility was placed in service in January 2011.

In March 2008, certain environmental and preservation groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was in violation of certain environmental laws and demanded relief, including suspension or termination of the program. The plaintiffs voluntarily dismissed their complaint in August 2010.

Components of deferred income taxes included in the Balance Sheets are shown below:

	Successor December 31, 2010	Predecessor December 31, 2009
Deferred income tax liabilities:		
Depreciation and other plant-related items	$ 347	$ 303
Regulatory assets and other	133	69
Total deferred income tax liabilities	480	372
Deferred income tax assets:		
Regulatory liabilities and other	80	-
Income taxes due to customers	2	4
Pensions and related benefits	9	17
Liabilities and other	19	18
Total deferred income tax assets	110	39
Net deferred income tax liabilities	$ 370	$ 333
Balance sheet classification:		
Prepayments and other current assets	$ (6)	$ (3)
Deferred income taxes (non-current)	376	336
Net deferred income tax liabilities	$ 370	$ 333

The Company expects to have adequate levels of taxable income to realize its recorded deferred income tax assets.

A reconciliation of differences between the income tax expense at the statutory U.S. federal income tax rate and KU's actual income tax expense follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Statutory federal income tax expense	$ 19	$ 77	$ 70	$ 79
State income taxes – net of federal benefit	2	8	5	5
Qualified production activities deduction	(1)	(4)	(1)	(3)
Dividends received deduction related to EEI investment	-	-	(3)	(8)
Reversal of excess deferred taxes	-	(2)	(2)	(1)
Other differences – net	-	(1)	(2)	(4)
Income tax expense	$ 20	$ 78	$ 67	$ 68
Effective income tax rate	36.4%	35.8%	33.5%	30.1%

The Tax Relief, Unemployment Reauthorization and Job Creation Act of 2010, enacted December 17, 2010 provided, among other provisions, certain incentives related to bonus depreciation and 100% expensing of qualifying capital expenditures. KU benefited from these new provisions by reducing its 2010 current federal income tax expense. This reduction in federal taxable income for KU does, however, result in a reduction of KU's Section 199 Manufacturing deduction, which is based on manufacturing taxable income and correspondingly increases income tax expense. The impact from these changes on 2010 was not material; however, KU anticipates a significant reduction of taxable income in 2011 and 2012 and a corresponding loss of most, if not all, of the Section 199 Manufacturing deduction for the following two years.

Note 11 - Long-Term Debt

As summarized below, at December 31, 2010, long-term debt consisted of first mortgage bonds and secured pollution control bonds. At December 31, 2009, long-term debt and the current portion of long-term debt consisted primarily of pollution control bonds and long-term loans from affiliated companies.

	Successor	Predecessor
	2010	2009
Current portion of long-term debt to affiliates	$ -	$ 33
Long-term debt to affiliated companies	-	1,298
Secured first mortgage bonds, net of debt discount and amortization of debt discount	1,500	-
Pollution control revenue bonds, collateralized by first mortgage bonds	351	351
Fair value adjustment from purchase accounting	1	-
Unamortized discount	(11)	-
Total long-term debt	1,841	1,682
Less current portion	-	261
Long-term debt, excluding current portion	$ 1,841	$ 1,421

	Stated Interest Rates	Maturities	Debt Amounts
Successor			
Outstanding at December 31, 2010:			
Current portion	N/A	N/A	$ -
Non-current portion	Variable – 6.00%	2015-2040	1,841
Predecessor			
Outstanding at December 31, 2009:			
Current portion	Variable – 4.240%	2010-2034	$ 261
Non-current portion	Variable – 7.035%	2011-2037	1,421

As of December 31, 2009, long-term debt includes $228 million of pollution control bonds that were classified as current portion because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include Carroll County 2002 Series A and B, 2004 Series A, 2006 Series B and 2008 Series A; Muhlenberg County 2002 Series A; and Mercer County 2000 Series A and 2002 Series A. Maturity dates for these bonds range from 2023 to 2034. As of December 31, 2009, the bonds were classified as current portion of long-term debt because investors could put the bonds back to the Company within one year. As of December 31, 2010, the bonds were reclassified as long-term debt. See Note 1, Summary of Significant Accounting Policies, for changes in classification.

Pollution control bonds are obligations of KU issued in connection with tax-exempt pollution control bonds by various counties in Kentucky. A loan agreement obligates the Company to make debt service payments to the counties in amounts equal to the debt service due from the counties on the related pollution control bonds. Depending on the type of expense, the Successor capitalized debt expenses in long-term other regulatory assets or long-term other assets to align with the term of the debt for which the

expenses were related. The Predecessor capitalized debt expenses in current or long-term other regulatory assets or other current or long-term other assets based on the amount of expense expected to be recovered within the next year through rate recovery. Both Predecessor and Successor amortized debt expenses over the lives of the related bond issues. The Predecessor presentation and the Successor presentation are both appropriate under regulatory practices and GAAP.

In October 2010, in order to secure their respective obligations with respect to the pollution control bonds, KU issued first mortgage bonds to the pollution control bond trustees. KU's first mortgage bonds contain terms and conditions that are substantially parallel to the terms and conditions of the counties' debt, but provide that obligations are deemed satisfied to the extent of payments under the related loan agreement, and thus generally require no separate payment of principal and interest except under certain circumstances, including should KU default on the respective loan agreement. Also in October 2010, one national rating agency revised downward the short-term credit rating of the pollution control bonds and the Company's issuer rating as a result of the pending acquisition by PPL.

Several series of KU's pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At December 31, 2010, KU had an aggregate $351 million of outstanding pollution control indebtedness, of which $96 million is in the form of insured auction rate securities wherein interest rates are reset every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. Since 2008, interest rates increased and the Company experienced "failed auctions" when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture.

The average annualized interest rates on the auction rate bonds follow:

Successor	Predecessor	
November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	December 31, 2009
0.53%	0.51%	0.44%

The instruments governing this auction rate bond permit KU to convert the bond to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently.

As a result of downgrades of the monoline insurers by all of the rating agencies to levels below that of the Company's rating, the debt ratings of the Company's insured bonds are all based on the Company's senior secured debt rating and are not influenced by the monoline bond insurer ratings.

In connection with the PPL acquisition, on November 1, 2010, KU borrowed $1,331 million from a PPL subsidiary, in order to repay loans from a subsidiary of E.ON. KU used the net proceeds received from the sale of the first mortgage bonds to repay the debt owed to the PPL subsidiary arising from the borrowing.

In November 2010, KU issued first mortgage bonds totaling $1,500 million and used the proceeds to repay the loans from a PPL subsidiary mentioned above and for general corporate purposes. The first mortgage bonds were issued at a discount as described in the table below:

First Mortgage Bonds	Principal	Discount Price	First Mortgage Bonds Proceeds (a)
Series due 2015	$ 250	99.650%	$ 249
Series due 2020	500	99.622%	498
Series due 2040	750	98.915%	742
Total	$ 1,500		$ 1,489

(a) Before expenses other than discount to Purchaser

The first mortgage bonds were issued by KU in accordance with the rules of Section 144A of the Securities Act of 1933. KU has entered into a registration rights agreement in which it has agreed to file a registration statement with the SEC relating to an offer to exchange the first mortgage bonds for publicly tradable securities having substantially identical terms. If ultimate registration and/or certain milestones are not completed by certain dates in mid- and late 2011, the Company has agreed to pay liquidated damages to the bondholders. The liquidated damages would total 0.25% per annum of the principal amount of the bonds for the first 90 days and 0.50% per annum of the principal amount thereafter until the conditions described above have been cured.

There were no redemptions or maturities of long-term debt for 2009. Redemptions and maturities of long-term debt for 2010 are summarized below:

Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
Successor					
2010	Due to PPL Investment Corp.	$ 1,331	4.24%-7.035%	Unsecured	2010-2037
2010	Due to E.ON affiliates	1,331	4.24%-7.035%	Unsecured	2010-2037

Issuances of long-term debt for 2010 and 2009 are summarized below:

Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
Successor					
2010	Due to PPL Investment Corp.	$ 1,331	4.24%-7.035%	Unsecured	2010-2037
2010	First mortgage bonds	250	1.625%	Secured	2015
2010	First mortgage bonds	500	3.25%	Secured	2020
2010	First mortgage bonds	750	5.125%	Secured	2040
Predecessor					
2009	Due to E.ON affiliates	50	4.445%	Unsecured	2019
2009	Due to E.ON affiliates	50	4.81%	Unsecured	2019
2009	Due to E.ON affiliates	50	5.28%	Unsecured	2017

As of December 31, 2010, all of the Company's long-term debt is secured by a first mortgage lien on substantially all of the real and tangible personal property of the Company located in Kentucky.

Long-term debt maturities for KU are shown in the following table:

2011	$	-
2012		-
2013		-
2014		-
2015		250
Thereafter		1,601
	$	1,851

KU was in compliance with all debt covenants at December 31, 2010.

See Note 1, Summary of Significant Accounting Policies, for certain debt refinancing and associated transactions completed by KU in connection with the PPL acquisition, Note 2, Acquisition by PPL, for the adjustment made to the pollution control bonds to reflect fair value and Note 15, Related Party Transactions, for long-term debt payable to affiliates.

Note 12 - Notes Payable and Other Short-Term Obligations

Intercompany Revolving Line of Credit

KU participates in an intercompany money pool agreement wherein LKE and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) of up to $400 million. Details of the balances are as follows:

	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2010, Successor	$ 400	$ 10	$ 390	0.25%
December 31, 2009, Predecessor	400	45	355	0.20%

LKE maintains revolving credit facilities totaling $300 million at December 31, 2010 and $313 million at December 31, 2009, to ensure funding availability for the money pool. At December 31, 2010, the LKE facility is with PPL Investment Corp. LKE pays PPL Investment Corp. an annual commitment fee based on the Utilities' current bond ratings on the unused portion of the commitment. At December 31, 2009, one facility, totaling $150 million, was with E.ON North America, Inc., while the remaining line, totaling $163 million, was with Fidelia, both affiliated companies of E.ON. The balances are as follows:

	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2010, Successor	$ 300	$ -	$ 300	N/A
December 31, 2009, Predecessor	313	276	37	1.25%

Bank Revolving Line of Credit

As of December 31, 2010, the Company maintained a $400 million revolving line of credit with a group of banks maturing in December 2014. The revolving line of credit allows KU to issue letters of credit or borrow funds up to $400 million. Outstanding letters of credit reduce the facility's available borrowing capacity. The Company pays the banks an annual commitment fee based on current bond ratings on the unused portion of the commitment. At December 31, 2010, there was no amount borrowed under this facility although letters of credit totaling $198 million have been issued under this facility. This credit agreement contains financial covenants requiring the borrower's debt to total capitalization ratio to not exceed 70%, as calculated pursuant to the credit agreement, and other customary covenants.

As of December 31, 2009, the Company maintained a $35 million bilateral line of credit with an unaffiliated financial institution maturing in June 2012. The Company paid the banks an annual commitment fee on the unused portion of the commitment. At December 31, 2009, there was no balance outstanding under this facility. This facility was terminated on November 1, 2010, in conjunction with the PPL acquisition.

On December 1, 2010, KU replaced the letters of credit issued under prior letter of credit facilities with letters of credit of the same amount issued under the revolving line of credit. The four letter of credit facilities were subsequently terminated.

KU was in compliance with all line of credit covenants at December 31, 2010.

See Note 1, Summary of Significant Accounting Policies, for certain debt refinancing and associated transactions completed by KU in connection with the PPL acquisition and Note 15, Related Party Transactions, for long-term debt payable to affiliates.

Note 13 - Commitments and Contingencies

Operating Leases

KU leases office space, office equipment, plant equipment, real estate, railcars, telecommunications and vehicles and accounts for these leases as operating leases. In addition, KU reimburses LG&E for a portion of the lease expense paid by LG&E for KU's usage of office space leased by LG&E. Total lease expense was $10 million, $10 million and $9 million for 2010, 2009 and 2008, respectively. The future minimum annual lease payments for operating leases for years subsequent to December 31, 2010, are shown in the following table:

2011	$ 8
2012	7
2013	5
2014	5
2015	3
Thereafter	1
	$ 29

Owensboro Contract Litigation and Termination

In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. In May 2009, KU and OMU executed a settlement agreement resolving the matter on a basis consistent with prior court rulings and KU has received the agreed settlement amounts. Pursuant to the settlement's operation, the OMU Agreement terminated in May 2010.

Sale and Leaseback Transaction

The Company is a participant in a sale and leaseback transaction involving its 62% interest in two jointly owned CTs at KU's E.W. Brown generating station (Units 6 and 7). Commencing in December 1999, KU and LG&E entered into a tax-efficient, 18-year lease of the CTs. The Utilities have provided funds to fully defease the lease and have executed an irrevocable notice to exercise an early purchase option contained in the lease after 15.5 years. The financial statement treatment of this transaction is no different than if the Utilities had retained its ownership interest. The leasing transaction was entered into following receipt of required state and federal regulatory approvals. At December 31, 2010, the Balance Sheets included these assets at a value of $65 million, which is reflected in "Regulated utility plant – electric."

In case of default under the lease, the Company is obligated to pay to the lessor its share of certain fees or amounts. Primary events of default include loss or destruction of the CTs, failure to insure or maintain the CTs and unwinding of the transaction due to governmental actions. No events of default currently exist with respect to the lease. Upon any termination of the lease, whether by default or expiration of its term, title to the CTs reverts jointly to KU and LG&E.

At December 31, 2010, the maximum aggregate amount of default fees or amounts was $7 million, of which KU would be responsible for 62% (approximately $4 million). The Company has made arrangements with LKE, via guarantee and regulatory commitment, for LKE to pay its full portion of any default fees or amounts.

Letters of Credit

KU has provided letters of credit as of December 31, 2010 and 2009, for on-balance sheet obligations totaling $198 million to support bonds of $195 million and letters of credit for off-balance sheet obligations totaling less than $1 million to support certain obligations related to workers' compensation.

Commodity Purchases

OVEC

KU has a contract for power purchases with OVEC, terminating in 2026, for various Mw capacities. KU holds a 2.5% investment interest in OVEC with ten other electric utilities. KU is not the primary beneficiary; therefore, the investment is not consolidated into the Company's financial statements, but is recorded on the cost basis. OVEC is located in Piketon, Ohio, and owns and operates two coal-fired power plants, Kyger Creek Station in Ohio, and Clifty Creek Station in Indiana. KU is contractually entitled to 2.5% of OVEC's output, approximately 60 Mw of nameplate generation capacity. Pursuant to

the OVEC power purchase contract, the Company may be conditionally responsible for a 2.5% pro-rata share of certain obligations of OVEC under defined circumstances. These contingent liabilities may include unpaid OVEC indebtedness as well as shortfall amounts in certain excess decommissioning costs and postretirement benefits other than pension. KU's contingent potential proportionate share of OVEC's December 31, 2010 outstanding debt was $35 million. Future obligations for power purchases from OVEC are demand payments, comprised of annual minimum debt service payments, as well as contractually required reimbursement of plant operating, maintenance and other expenses, and are shown in the following table:

2011	$ 9
2012	10
2013	10
2014	10
2015	10
Thereafter	114
	$ 163

Coal and Natural Gas Transportation Purchase Obligations

KU has contracts to purchase coal and natural gas transportation. Future obligations are shown in the following table:

2011	$ 439
2012	200
2013	144
2014	93
2015	91
Thereafter	14
	$ 981

Construction Program

KU had approximately $116 million of commitments in connection with its construction program at December 31, 2010.

In June 2006, KU entered into a construction contract regarding the TC2 project. The contract is generally in the form of a turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price. During 2009 and 2010, KU received several contractual notices from the TC2 construction contractor asserting historical force majeure and excusable event claims for a number of adjustments to the contract price, construction schedule, commercial operations date, liquidated damages or other relevant provisions. In September 2010, KU and the construction contractor agreed to a settlement to resolve the force majeure and excusable event claims occurring through July 2010, under the TC2 construction contract, which settlement provided for a limited, negotiated extension of the contractual commercial operations date and/or relief from liquidated damage calculations. With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand

since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. KU cannot currently estimate the ultimate outcome of these matters.

TC2 Air Permit

The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the KDAQ in November 2005. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an Order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the two EPA objections. In March 2010, the Sierra Club submitted a petition to the EPA to object to the permit revision, which is now pending before the EPA. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the EPA issues a final ruling on the pending petition and all applicable appeals have been exhausted, the Company cannot predict the final outcome of this matter.

Environmental Matters

The Company's operations are subject to a number of environmental laws and regulations in each of the jurisdictions in which it operates governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety. As indicated below and summarized at the conclusion of this section, evolving environmental regulations will likely increase the level of capital and operating and maintenance expenditures incurred by the Company during the next several years. Based upon prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

Ambient Air Quality

The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS

through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which required additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provided for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR.

In July 2008, a federal appeals court issued a ruling finding deficiencies in the CAIR and vacating it. In December 2008, the Court amended its previous Order, directing the EPA to promulgate a new regulation but leaving the CAIR in place in the interim. The remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and the Utilities' compliance plans relating thereto due to the interconnection of the CAIR with such associated programs.

In January 2010, the EPA proposed a revised NAAQS for ozone which would increase the stringency of the standard. In addition, the EPA published final revised NAAQS standards for NO_2 and SO_2 in February 2010 and June 2010, respectively, which are more stringent than previous standards. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the revised NAAQS standards, KU's power plants are potentially subject to requirements for additional reductions in SO_2 and NOx emissions.

In July 2010, the EPA issued the proposed CATR, which serves to replace the CAIR. The CATR provides for a two-phase SO_2 reduction program with Phase I reductions due by 2012 and Phase II reductions due by 2014. The CATR provides for NOx reductions in 2012, but the EPA advised that it is studying whether additional NOx reductions should be required for 2014. The CATR is more stringent than the CAIR as it accelerates certain compliance dates and provides for only intrastate and limited interstate trading of emission allowances. In addition to its preferred approach, the EPA is seeking comment on an alternative approach which would provide for individual emission limits at each power plant. The EPA has announced that it will propose additional "transport" rules to address compliance with revised NAAQS standards for ozone and particulate matter which will be issued by the EPA in the future, as discussed below.

Hazardous Air Pollutants

As provided in the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provided for reductions of

70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The EPA has entered into a consent decree requiring it to promulgate a utility Maximum Achievable Control Technology rule to replace the CAMR with a proposed rule due by March 2011 and a final rule by November 2011. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new rules with different or more stringent requirements for reduction of mercury and other hazardous air pollutants. Kentucky has also repealed its corresponding state mercury regulations.

Acid Rain Program

The Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The Clean Air Act also contains requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze

The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its Clean Air Visibility Rule detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR provided for more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPs incorporate certain CAIR requirements, the remand of the CAIR could potentially impact regional haze SIPs. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls

Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. KU met its Phase I SO_2 requirements primarily through installation of FGD equipment on Ghent Unit 1. KU's strategy for its Phase II SO_2 requirements, which commenced in 2000, includes the installation of additional FGD equipment, as well as using accumulated emission allowances and fuel switching to defer certain additional capital expenditures and continue to evaluate improvements to further reduce SO_2 emissions. KU believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. KU's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. KU will

continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. KU expects to incur additional capital expenditures currently approved in its ECR plans totaling approximately $500 million during the 2011 through 2013 time period to achieve emissions reductions and manage coal combustion residuals. Monthly recovery is subject to periodic review by the Kentucky Commission.

GHG Developments

In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. As discussed below, legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs, including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are on-going. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark, in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. In Copenhagen, the U.S. made a nonbinding commitment to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations met in Cancun, Mexico, in December 2010 to continue negotiations toward a binding agreement.

GHG Legislation

KU is monitoring on-going efforts to enact GHG reduction requirements and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, which was a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. The bill provided for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020 and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would have initially been allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would have also established a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contained additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency.

In September 2009, the Clean Energy Jobs and American Power Act, which was largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raised the emissions reduction target for 2020 to 20% below 2005 levels and did not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision incorporated allowance allocation provisions similar to the House bill. Although Senators Kerry and Lieberman and others worked to reach a consensus on GHG legislation, no bill passed the Senate in 2010. The Company is closely monitoring the progress of pending energy legislation, but the prospect for passage of comprehensive GHG legislation in 2011 is uncertain.

GHG Regulations

In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. In April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities are required to submit annual reports commencing with calendar year 2010. In May 2010, the EPA issued a final GHG "tailoring" rule, effective January 2011, requiring new or modified sources with GHG emissions equivalent to at least 75,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the rule. The final rule will apply to new and modified power plants beginning in January 2011. The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations. In December 2010, the EPA announced that it plans to promulgate GHG New Source Performance Standards for power plants, including both new and existing facilities. A proposed rule is expected by July 2011, while a final rule is expected by May 2012. In the absence of either a proposed or final regulation, KU is unable to assess the potential impact of any future regulation.

GHG Litigation

A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, a three judge panel of the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. In March 2010, the court vacated the opinion of the three-judge panel and granted a motion for rehearing but subsequently denied the appeal due to the lack of a quorum. The appellate ruling leaves in effect the lower court ruling dismissing the plaintiffs' claims. In January 2011, the Supreme Court denied petitioner's petition for review, which effectively brings the case to an end. The Comer complaint alleged that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. E.ON, the former indirect parent of the Utilities, was named as a defendant in the complaint but was not a party to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. KU continues to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to operations.

Ghent Opacity NOV

In September 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July of 2007 at Units 1 and 3 of KU's Ghent generating station. The parties have met on this matter and KU has received no further communications from the EPA. The Company is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

Ghent New Source Review NOV

In March 2009, the EPA issued an NOV alleging that KU violated certain provisions of the Clean Air Act's rules governing new source review and prevention of significant deterioration by installing FGD and SCR controls at its Ghent generating station without assessing potential increased sulfuric acid mist emissions. KU contends that the work in question, as pollution control projects, was exempt from the requirements cited by the EPA. In December 2009, the EPA issued a Section 114 information request seeking additional information on this matter. In March 2010, the Company received an EPA settlement proposal providing for imposition of additional permit limits and emission controls and anticipates continued settlement negotiations with the EPA. Negotiations between the EPA and KU are ongoing. Depending on the provisions of a final settlement or the results of litigation, if any, resolution of this matter could involve significant increased operating and capital expenditures. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination on the Company's financial position or results of operations.

Ash Ponds and Coal-Combustion Byproducts

The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the TVA's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including KU, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of KU's impoundments, which the EPA found to be in satisfactory condition. In June 2010, the EPA published proposed regulations for coal combustion byproducts handled in landfills and ash ponds. The EPA has proposed two alternatives: (1) regulation of coal combustion byproducts in landfills and ash ponds as a hazardous waste or (2) regulation of coal combustion byproducts as a solid waste with minimum national standards. Under both alternatives, the EPA has proposed safety requirements to address the structural integrity of ash ponds. In addition, the EPA will consider potential refinements of the provisions for beneficial reuse of coal combustion byproducts.

Water Discharges and PCB Regulations

The EPA has also announced plans to develop revised effluent limitation guidelines governing discharges from power plants and standards for cooling water intake structures. The EPA has further announced plans to develop revised standards governing the use of polychlorinated biphenyls ("PCB") in electrical equipment. The Company is monitoring these ongoing regulatory developments but will be unable to determine the impact until such time as new rules are finalized.

Impact of Pending and Future Environmental Developments

As a company with significant coal-fired generating assets, KU will likely be substantially impacted by pending or future environmental rules or legislation requiring mandatory reductions in GHG emissions or other air emissions, imposing more stringent standards on discharges to waterways, or establishing additional requirements for handling or disposal of coal combustion byproducts. These evolving environmental regulations will likely require an increased level of capital expenditures and increased incremental operating and maintenance costs by the Company over the next several years. Due to the uncertain nature of the final regulations that will ultimately be adopted by the EPA, including the

reduction targets and the deadlines that will be applicable, the Company cannot finalize estimates of the potential compliance costs, but should the final rules incorporate additional emission reduction requirements, require more stringent emissions controls or implement more stringent byproducts storage and disposal practices, such costs will likely be significant. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based upon a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Capital expenditures for KU associated with such actions are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary. With respect to potential developments in water discharge, revised PCB standards or GHG initiatives, costs in such areas cannot be estimated due to the preliminary status or uncertain outcome of such developments, but would be in addition to the above amount and could be substantial. Ultimately, the precise impact on the Company's operations of these various environmental developments cannot be determined prior to the finalization of such requirements. Based upon prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

TC2 Water Permit

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County generating station. In October 2010, the hearing officer issued a report and recommended Order providing for dismissal of the claims raised by the petitioners. In December 2010, the Secretary issued a final Order dismissing all claims and upholding the permit which petitioners subsequently appealed to Trimble County Circuit Court.

General Environmental Proceedings

From time to time, KU appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include a prior Section 114 information request from the EPA relating to new-source review issues at KU's Ghent unit 2; completed settlement with state regulators regarding compliance with particulate limits in the air permit for KU's Tyrone generating station; remediation obligations or activities for or other risks relating to elevated PCB levels at existing properties; liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites; and on-going claims regarding the GHG emissions from the Company's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the Company's operations.

Note 14 - Jointly Owned Electric Utility Plant

TC2 is a jointly owned unit at the Trimble County site. KU and LG&E own undivided 60.75% and 14.25% interests, respectively. Of the remaining 25%, IMEA owns a 12.12% undivided interest and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate share of capital cost during construction and fuel, operation and maintenance cost when TC2 is in-service. With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. In December 2009 and June 2008, LG&E sold assets to KU related to the construction of TC2 with a net book value of $48 million and $10 million, respectively.

The following data represent shares of the jointly owned property (capacity based on nameplate rating):

	TC2				
	KU	LG&E	IMPA	IMEA	Total
Ownership interest	60.75%	14.25%	12.88%	12.12%	100%
Mw capacity	509	119	108	102	838

KU's 60.75% ownership:		LG&E's 14.25% ownership:	
Plant held for future use	$ 62	Plant held for future use	$ 2
Construction work in progress	703	Construction work in progress	187
Accumulated depreciation	(1)	Accumulated depreciation	-
Net book value	$ 764	Net book value	$ 189

KU and LG&E jointly own the following CTs and related equipment (capacity based on net summer capability) as of December 31, 2010:

	KU				LG&E				Total			
Ownership Percentage	Mw Capacity	Cost	Depr.	Net Book Value	Mw Capacity	Cost	Depr.	Net Book Value	Mw Capacity	Cost	Depr.	Net Book Value
KU 47%, LG&E 53% (a)	129	$ 43	$ -	$ 43	146	$ 48	$ -	$ 48	275	$ 91	$ -	$ 91
KU 62%, LG&E 38% (b)	190	64	(2)	62	118	40	(2)	38	308	104	(4)	100
KU 71%, LG&E 29% (c)	228	63	(1)	62	92	26	-	26	320	89	(1)	88
KU 63%, LG&E 37% (d)	404	109	(1)	108	236	64	(1)	63	640	173	(2)	171
KU 71%, LG&E 29% (e)	n/a	4	-	4	n/a	2	-	2	n/a	6	-	6

(a) Comprised of Paddy's Run 13 and E.W. Brown 5. In addition to the above jointly owned utility plant, there is an inlet air cooling system attributable to unit 5 and units 8-11 at the E.W. Brown facility. This inlet air cooling system is not jointly owned, however, it is used to increase production on the units to which it relates, resulting in an additional 88 Mw of capacity for KU.

(b) Comprised of units 6 and 7 at the E.W. Brown facility.
(c) Comprised of units 5 and 6 at the Trimble County facility.
(d) Comprised of CT Substation 7-10 and units 7, 8, 9 and 10 at the Trimble County facility.
(e) Comprised of CT Substation 5 and 6 and CT Pipeline at the Trimble County facility.

Both KU's and LG&E's participating share of direct expenses of the jointly owned plants is included in the corresponding operating expenses on each company's respective Statements of Income (i.e., fuel, maintenance of plant, other operating expense).

Note 15 - Related Party Transactions

KU and subsidiaries of LKE and PPL engage in related party transactions. Transactions between KU and LKE subsidiaries are eliminated on consolidation of LKE. Transactions between KU and PPL subsidiaries are eliminated on consolidation of PPL. These transactions are generally performed at cost and are in accordance with FERC regulations under PUHCA 2005 and the applicable Kentucky Commission and Virginia Commission regulations.

Intercompany Wholesale Sales and Purchases

KU and LG&E jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are recorded as intercompany wholesale sales and purchases are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the Utilities. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

These sales and purchases are included in the Statements of Income as "Operating revenues", "Power purchased" expenses and "Other operation and maintenance expenses". KU's intercompany electric revenues and power purchased expenses were as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Electric operating revenues from LG&E	$ 2	$ 13	$ 21	$ 80
Power purchased and related operations and maintenance expenses from LG&E	21	79	101	109

Interest Charges

See Note 11, Long-Term Debt, and Note 12, Notes Payable and Other Short-Term Obligations, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

KU's interest expense to affiliated companies was as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Interest on money pool loans	$ -	$ -	$ -	$ 2
Interest on PPL loans	2	-	-	-
Interest on Fidelia loans	-	62	69	56

Interest paid to LKE on the money pool arrangement was less than $1 million for 2010 and 2009.

Dividends

In September 2010, the Company paid dividends of $50 million to its sole shareholder, LKE.

Capital Contributions

The Company received no capital contributions in 2010, but received capital contributions of $75 million and $145 million from its sole shareholder, LKE, in 2009 and 2008, respectively.

Sale of Assets

In 2010, KU sold and bought assets of less than $1 million to and from LG&E. In December 2009, LG&E sold assets to KU related to the construction of TC2 with a net book value of $48 million.

Other Intercompany Billings

Servco provides the Company with a variety of centralized administrative, management and support services. Associated charges include payroll taxes paid by Servco on behalf of KU, labor and burdens of Servco employees performing services for KU, coal purchases and other vouchers paid by Servco on behalf of KU. The cost of these services is directly charged to the Company, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and/or other statistical information. These costs are charged on an actual cost basis.

In addition, the Utilities provide services to each other and to Servco. Billings between the Utilities relate to labor and overheads associated with union and hourly employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from KU to Servco include cash received by Servco on behalf of KU, tax settlements and other payments

made by the Company on behalf of other non-regulated businesses which are reimbursed through Servco.

Intercompany billings to and from KU were as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Servco billings to KU	$ 46	$ 233	$ 169	$ 227
LG&E billings to KU	14	49	44	5
KU billings to Servco	12	11	14	3
KU billings to LG&E	-	-	78	75

<u>Intercompany Balances</u>

The Company had the following balances with its affiliates:

	Successor	Predecessor
	December 31, 2010	December 31, 2009
Accounts receivable from LKE	$ 12	$ 9
Accounts payable to LG&E	22	53
Accounts payable to Servco	23	20
Accounts payable to Fidelia	-	15
Notes payable to LKE	10	45
Long-term debt to Fidelia	-	1,331

Note 16 - Selected Quarterly Data (Unaudited)

	For the 2010 Periods Ended (a)				
	Predecessor				Successor
	March 31	June 30	September 30	October 31	December 31
Operating revenues	$ 380	$ 350	$ 416	$ 102	$ 263
Operating income	87	71	105	22	65
Net income	44	31	54	11	35

(a) Periods ended March 31, June 30 and September 30 represent three months then ended. Period ended October 31 represents one month then ended and period ended December 31 represents two months then ended.

	For the 2009 Quarters Ended			
	Predecessor			
	March 31	June 30	September 30	December 31
Operating revenues	$ 363	$ 305	$ 341	$ 346
Operating income	19	53	125	72
Net income	7	26	66	34

Note 17 - Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consisted of the following:

	Pre-Tax Accumulated Derivative Gain (Loss)	Income Taxes	Net
Balance at December 31, 2009, Predecessor	$ -	$ -	$ -
Equity investee's other comprehensive income (loss)	(3)	1	(2)
Balance at October 31, 2010, Predecessor	(3)	1	(2)
Effect of PPL acquisition	3	(1)	2
Balance at December 31, 2010, Successor	$ -	$ -	$ -

Note 18 - Subsequent Events

Subsequent events have been evaluated through February 25, 2011, the date of issuance of these statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

On January 31, 2011, KU filed a notice of intent to file a rate case with the Virginia Commission for the test year ended December 31, 2010. The case is expected to be filed on or after April 1, 2011.

With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. LG&E and KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages.

On January 14, 2011, KU contributed $43 million to its pension plan.

Report of Independent Auditors

To Stockholder of Kentucky Utilities Company

In our opinion, the accompanying balance sheet and the related statements of income, retained earnings, comprehensive income, cash flows, and capitalization present fairly, in all material respects, the financial position of Kentucky Utilities Company (Successor Company) at December 31, 2010 and the results of its operations and its cash flows for the period from November 1, 2010 to December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assertion of the effectiveness of internal control over financial reporting, included in "Management's Report of Internal Controls Over Financial Reporting" which appears on page 50. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audit. We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States) and in accordance with the auditing and attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

As discussed in Note 2 to the financial statements, on November 1, 2010, PPL Corporation completed its acquisition of LG&E and KU Energy LLC and its subsidiaries. The push-down basis of accounting was used at the acquisition date.

A company's internal control over financial reporting is a process effected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial

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statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and those charged with governance and (iii) provide reasonable assurance regarding prevention or timely detection and correction of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect and correct misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Louisville, Kentucky
February 25, 2011

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Report of Independent Auditors

To Stockholder of Kentucky Utilities Company

In our opinion, the accompanying balance sheet and the related statements of income, retained earnings, comprehensive income, cash flows, and capitalization present fairly, in all material respects, the financial position of Kentucky Utilities Company (Predecessor Company) at December 31, 2009 and the results of its operations and its cash flows for the period from January 1, 2010 to October 31, 2010 and for each of the two years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the financial statements, on November 1, 2010, PPL Corporation completed its acquisition of LG&E and KU Energy LLC and its subsidiaries. The push-down basis of accounting was used at the acquisition date.

PricewaterhouseCoopers LLP

Louisville, Kentucky
February 25, 2011

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Supplement, dated December 1, 2010 to Reoffering Circular dated December 10, 2008, as supplemented as of December 16, 2008 and October 29, 2010 (the "Reoffering Circular")

$12,900,000
County of Mercer, Kentucky
Solid Waste Disposal Facility Revenue Bonds, 2000 Series A
(Kentucky Utilities Company Project)

Effective as of December 1, 2010, through December 1, 2011 (the Letter of Credit (as defined below) expiration date, subject to extension or earlier termination), payment of the principal of and interest on the above-referenced bonds (the "Bonds") when due will be paid with funds drawn under an irrevocable transferable direct pay letter of credit (the "Letter of Credit") issued by

WELLS FARGO BANK, NATIONAL ASSOCIATION

The Letter of Credit will permit the Trustee to draw with respect to the Bonds up to an amount sufficient to pay (i) the principal thereof (or that portion of the purchase price corresponding to principal) plus (ii) interest thereon (or that portion of the purchase price corresponding to interest) at an assumed rate of 10% per annum for at least 45 days.

The Bonds will continue to bear interest at a Weekly Rate, determined by the Remarketing Agent in accordance with the Indenture, payable on the first Business Day of each calendar month, commencing on January 3, 2011. The interest rate period, interest rate and Interest Rate Mode will be subject to change under certain conditions, as described in the Reoffering Circular. The Bonds are subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption following a determination of taxability prior to maturity, as described in the Reoffering Circular. The Bonds are subject to mandatory purchase on any date on which the Bonds are converted to a different Interest Rate Mode and upon the expiration of the Letter of Credit or any Alternate Credit Facility.

This supplement contains a description of the Letter of Credit and Wells Fargo Bank, National Association, the issuer of the Letter of Credit. For purposes of the Reoffering Circular, the Letter of Credit is a "Credit Facility" and Wells Fargo Bank, National Association is a "Credit Facility Issuer." Except as otherwise specified herein, information in the Reoffering Circular referred to above has not been amended or modified and the information contained herein is qualified by reference to, and should be read in conjunction with, the Reoffering Circular, including information incorporated therein by reference. Terms not otherwise defined herein shall have the meanings ascribed to them in such Reoffering Circular.

The eighth paragraph under the section of the Reoffering Circular captioned "Introductory Statement" is hereby amended to read in its entirety as follows:

Effective December 1, 2010, the Company will cause to be delivered an irrevocable transferable direct pay letter of credit (the "Letter of Credit"), issued by Wells Fargo Bank, National Association (the "Bank"), to provide for the timely payment of principal of and accrued interest (calculated for at least 45 days at the maximum rate of 10% per annum) on, and purchase price of, the Bonds. The Company will be required to reimburse the Bank for all amounts drawn by the Trustee under the Letter of Credit pursuant to the terms of a certain letter agreement, to be dated as of December 1, 2010 (the "Reimbursement Agreement"), between the Company and the Bank. The Letter of Credit will expire on December 1, 2011, unless extended or earlier terminated.

* * * *

The section of the Reoffering Circular captioned "The Letter of Credit" is hereby amended to read in its entirety as follows:

THE LETTER OF CREDIT

The following summarizes certain provisions of the Letter of Credit and the Reimbursement Agreement, to which reference is made for the detailed provisions thereof. Unless otherwise defined in this Reoffering Circular, capitalized terms in the following summary are used as defined in the Letter of Credit and the Reimbursement Agreement. The Company is permitted under the Indenture to deliver an Alternate Credit Facility to replace the Letter of Credit. Any such Alternate Credit Facility must meet certain requirements described in the Indenture.

The Letter of Credit

The Letter of Credit will be an irrevocable transferable direct pay letter of credit issued by the Bank in order to provide additional security for the payment of principal of, purchase

price of, interest on and premium, if applicable, on any date when payments under the Bonds are due, including principal and interest payments and payments upon tender, redemption, acceleration or maturity of the Bonds. The Letter of Credit will provide for direct payments to or upon the order of the Trustee as set forth in the Letter of Credit in amounts sufficient to pay such amounts in accordance with the terms thereof.

The Letter of Credit will be issued in an amount equal to the aggregate principal amount of the outstanding Bonds, plus an amount that represents interest accrued thereon at an assumed rate of 10% per annum for 45 days (the "Credit Amount"). The Trustee, upon compliance with the terms of the Letter of Credit, is authorized to draw up to (a) an amount sufficient (i) to pay principal of the Bonds, when due, whether at maturity or upon redemption or acceleration, and (ii) to pay the portion of the purchase price of the Bonds delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed (a "Liquidity Drawing") equal to the principal amount of the Bonds, plus (b) an amount not to exceed 45 days of accrued interest on such Bonds at an assumed rate of 10% per annum (i) to pay interest on the Bonds, when due, and (ii) to pay the portion of the interest accrued on the Bonds as of any Liquidity Drawing.

The amount available under the Letter of Credit will be automatically reduced by the amount of any drawing thereunder, subject to reinstatement as described below. With respect to a drawing by the Trustee solely to pay interest on the Bonds on an Interest Payment Date, the amount available under the Letter of Credit will be automatically reinstated in the amount of such drawing effective on the earlier of (i) receipt by the Bank from the Company of reimbursement of any drawing solely to pay interest in full or (ii) at the opening of business on the eleventh calendar day after the date the Bank honors such drawing, unless the Trustee has received written notice from the Bank by the tenth calendar day after the date the Bank honors such drawing the Bank is not so reinstating the available amount due to the Company's failure to reimburse the Bank for such drawing in full, or that an event of default has occurred and is continuing under the Reimbursement Agreement and, in either case, directing, an acceleration of the Bonds pursuant to the Indenture. With respect to a Liquidity Drawing under the Letter of Credit, the amount available under the Letter of Credit will be automatically reduced by the principal amount of the Bonds purchased with the proceeds of such drawing plus the amount of accrued interest on such Bonds. In the event of the remarketing of the Bonds purchased with the proceeds of a Liquidity Drawing, the amount available under the Letter of Credit will be automatically reinstated upon receipt by the Bank or the Trustee on the Bank's behalf of an amount equal to such principal amount plus accrued interest.

The Letter of Credit will terminate on the earliest to occur of:

(i) the Bank's close of business on December 1, 2011 (such date, as extended from time to time in accordance with the Letter of Credit is defined as the "Stated Expiration Date");

(ii) the Bank's close of business on the date which is five Business Days following the date of receipt by the Bank of a certificate from the Trustee certifying that (a) no Bonds remain Outstanding within the meaning of the Indenture, (b) all drawings required to be made under the Indenture and available under the Letter of Credit have been made and honored, (c) an Alternate Credit Facility has been delivered to the Trustee in accordance with the Indenture to replace the Letter of Credit or (d) all of the outstanding Bonds were converted to Bonds bearing interest at a rate other than the Daily Rate or the Weekly Rate;

(iii) the Bank's close of business on the date of receipt by the Bank of a certificate from the Trustee confirming that the Trustee is required to terminate the Letter of Credit in accordance with the terms of the Indenture;

(iv) the date on which the Bank receives and honors an acceleration drawing certificate; or

(v) the Bank's close of business on the date which is 30 days after receipt by the Trustee of written notice from the Bank of an Event of Default under the $400,000,000 Revolving Credit Agreement dated as of November 1, 2010 among the Company, the lending institutions party thereto from time to time and Wells Fargo Bank, National Association, as Administrative Agent (the "Credit Agreement") and instructing the Trustee to draw under the Letter of Credit.

The Reimbursement Agreement

Pursuant to the Reimbursement Agreement, the Company is obligated to reimburse the Bank for all amounts drawn under the Letter of Credit, and to pay interest on all such amounts. The Company has also agreed to pay the Bank a periodic fee for issuing and maintaining the Letter of Credit.

The Reimbursement Agreement, through incorporation of the terms of the Credit Agreement, imposes various covenants and agreements, including various financial and operating covenants, on the Company. Such covenants include, but are not limited to, covenants relating to (i) inspection of the books and financial records of the Company; (ii) mergers or consolidations; and (iii) disposition of assets. Any such covenants may be amended, waived or modified at any time by the Bank and without the consent of the Trustee or the holders of the Bonds. Under certain circumstances, the failure of the Company to comply with such covenants may result in a mandatory tender or acceleration of the Bonds.

An Event of Default under the Credit Agreement will constitute an Event of Default under the Reimbursement Agreement. The following events will constitute an Event of Default under the Credit Agreement:

(i) the Borrower shall fail to pay when due any principal on any Loans under the Credit Agreement or Reimbursement Obligations; or

(ii) the Company shall fail to pay when due any interest on the Loans under the Credit Agreement and Reimbursement Obligations, any fee or any other amount payable hereunder or under any other Loan Document for five (5) days following the date such payment becomes due thereunder; or

(iii) the Company shall fail to observe or perform certain covenants or agreements contained in the Credit Agreement, including those related to mergers, disposition of assets and capitalization ratios; or

(iv) the Company shall fail to give notice of a Default or Event of Default under the Credit Agreement within a specified number of days following knowledge of such occurrence; or

(v) the Company shall fail to observe or perform any covenant or agreement contained in the Credit Agreement or any notes issued thereunder (other than those covered above) for thirty (30) days after written notice thereof has been given to the defaulting party by the administrative agent, or at the request of the required lenders; or

(vi) any representation, warranty or certification made by the Company in the Credit Agreement or any notes issued thereunder or in any certificate, financial statement or other document delivered pursuant hereto or thereto shall prove to have been incorrect in any material respect when made or deemed made; or

(vii) the Company shall (i) fail to pay any principal or interest, regardless of amount, due in respect of any Material Debt beyond any period of grace provided with respect thereto, or (ii) fail to observe or perform any other term, covenant, condition or agreement contained in any agreement or instrument evidencing or governing any such Material Debt beyond any period of grace provided with respect thereto if the effect of any failure referred to in this clause (ii) is to cause, or to permit the holder or holders of such Debt or a trustee on its or their behalf to cause, such Debt to become due prior to its stated maturity; or

(viii) the Company shall commence a voluntary case or other proceeding seeking liquidation, reorganization or other relief with respect to itself or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any substantial part of its property, or shall consent to any such relief or to the appointment of or taking possession by any such official in an involuntary case or other proceeding commenced against it, or shall make a general assignment for the benefit of creditors, or shall fail generally to pay, or shall admit in writing its inability to pay, its debts as they become due, or shall take any corporate action to authorize any of the foregoing; or

(ix) an involuntary case or other proceeding shall be commenced against the Company seeking liquidation, reorganization or other relief with respect to it or its debts under any bankruptcy, insolvency or other similar law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of it or any substantial part of its property, and such involuntary case or other proceeding shall remain undismissed and unstayed for a period of 60 days; or an order for relief shall be entered against the Company under the Bankruptcy Code; or

(x) any member of the ERISA Group shall fail to pay when due an amount or amounts aggregating in excess of $50,000,000 which it shall have become liable to pay under Title IV of ERISA; or notice of intent to terminate a Material Plan shall be filed under Title IV of

ERISA by any member of the ERISA Group, any plan administrator or any combination of the foregoing; or the PBGC shall institute proceedings under Title IV of ERISA to terminate, to impose liability (other than for premiums under Section 4007 of ERISA) in respect of, or to cause a trustee to be appointed to administer any Material Plan; or a condition shall exist by reason of which the PBGC would be entitled to obtain a decree adjudicating that any Material Plan must be terminated; or there shall occur a complete or partial withdrawal from, or default, within the meaning of Section 4219(c)(5) of ERISA, with respect to, one or more Multiemployer Plans which could reasonably be expected to cause one or more members of the ERISA Group to incur a current payment obligation in excess of $50,000,000; or

(xi) the Company shall fail within sixty (60) days to pay, bond or otherwise discharge any judgment or order for the payment of money in excess of $20,000,000, entered against the Company that is not stayed on appeal or otherwise being appropriately contested in good faith; or

(xii) a Change of Control shall have occurred;

For purposes of the foregoing:

"Change of Control" means (i) the acquisition by any person, or two or more persons acting in concert, of beneficial ownership of 25% or more of the outstanding shares of voting stock of PPL Corporation or its successors or (ii) the failure at any time of PPL Corporation or its successors to own 80% or more of the outstanding shares of the voting stock in the Company.

"Credit Agreement" means the $400,000,000 Revolving Credit Agreement dated as of November 1, 2010 among the Company, the lending institutions party thereto from time to time and Wells Fargo Bank, National Association, as Administrative Agent.

"Material Debt" means debt (other than the notes issued under the Credit Agreement) of the Company in a principal or face amount exceeding $50,000,000

Appendix C of the Reoffering Circular is hereby amended to read in its entirety as follows:

Wells Fargo Bank, National Association

The information under this heading has been provided solely by Wells Fargo Bank, National Association and is believed to be reliable. This information has not been verified independently by the Company, the Issuer or the Remarketing Agent. The Company, the Issuer and the Remarketing Agent make no representation whatsoever as to the accuracy, adequacy or completeness of such information.

Wells Fargo Bank, National Association

Wells Fargo Bank, National Association (the "Bank") is a national banking association organized under the laws of the United States of America with its main office at 101 North Phillips Avenue, Sioux Falls, South Dakota 57104, and engages in retail, commercial and corporate banking, real estate lending and trust and investment services. The Bank is an indirect, wholly owned subsidiary of Wells Fargo & Company, a diversified financial services company, a financial holding company and a bank holding company registered under the Bank Holding Company Act of 1956, as amended, with its principal executive offices located in San Francisco, California.

Each quarter, the Bank files with the FDIC financial reports entitled "Consolidated Reports of Condition and Income for Insured Commercial Banks with Domestic and Foreign Offices," commonly referred to as the "Call Reports." The Bank's Call Reports are prepared in accordance with regulatory accounting principles, which may differ from generally accepted accounting principles. The publicly available portions of Call Reports filed by the Bank with the FDIC may be obtained from the FDIC, Disclosure Group, Room F518, 550 17th Street, N.W., Washington, D.C. 20429 at prescribed rates, or from the FDIC on its Internet site at http://www.fdic.gov, or by writing to Corporate Secretary's Office, Wells Fargo Center, Sixth and Marquette, MAC N9305-173, Minneapolis, MN 55479.

The Letter of Credit will be solely an obligation of the Bank and will not be an obligation of, or otherwise guaranteed by, Wells Fargo & Company, and no assets of Wells Fargo & Company or any affiliate of the Bank or Wells Fargo & Company will be pledged to the payment thereof. Payment of the Letter of Credit will not be insured by the FDIC.

The information contained in this section, including financial information, relates to and has been obtained from the Bank, and is furnished solely to provide limited introductory information regarding the Bank and does not purport to be comprehensive. Any financial information provided in this section is qualified in its entirety by the detailed information appearing in the Call Reports referenced above. The delivery hereof shall not create any implication that there has been no change in the affairs of the Bank since the date hereof.

Appendix A of the Reoffering Circular is hereby amended to read in its entirety as follows:

Appendix A

[DELETED AND REPLACED – SEE APPENDIX A TO SUPPLEMENT DATED MAY 2, 2011]

Supplement, dated October 29, 2010 to Reoffering Circular dated December 10, 2008, as supplemented as of December 16, 2008 (the "Reoffering Circular")

$12,900,000
County of Mercer, Kentucky
Solid Waste Disposal Facility Revenue Bonds, 2000 Series A
(Kentucky Utilities Company Project)

Effective as of October 29, 2010, the above-referenced bonds (the "Bonds") will be further secured by the delivery to The Bank of New York Mellon, as trustee for the Bonds (the "Trustee"), of a tranche of first mortgage bonds of Kentucky Utilities Company (the "Company"). The principal amount, maturity date and interest rate (or method of determining interest rates) of such tranche of first mortgage bonds will be identical to the principal amount, maturity date and interest rate (or method of determining interest rates) of the Bonds. The first mortgage bonds will only be payable, and interest thereon will only accrue, as described herein. See "Security," "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds" and "Summary of the First Mortgage Bonds" for more information regarding the first mortgage bonds. The first mortgage bonds will not provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase in accordance with the Indenture (as hereinafter defined).

Please be advised that, as reflected in the Company's most recent financial statements that are filed on the Electronic Municipal Market Access (EMMA) system and are incorporated by reference herein, PPL Corporation has entered into an agreement with E.ON AG pursuant to which PPL Corporation would purchase all of the ownership interests of E.ON U.S. LLC, the Company's parent. Consummation of the transaction is subject to customary closing conditions, including receipt of all required regulatory approvals. Subject to receipt of such approvals, the transaction is expected to close by the end of 2010. If the transaction is completed, the Company will become an indirect wholly-owned subsidiary of PPL Corporation.

Except as otherwise specified herein, information in the Reoffering Circular referred to above has not been amended or modified and the information contained herein is qualified by reference to, and should be read in conjunction with, the Reoffering Circular, including information incorporated therein by reference. Terms not otherwise defined herein shall have the meanings ascribed to them in such Reoffering Circular.

The section of the Reoffering Circular captioned "Security" is hereby amended to read in its entirety as follows:

Security

Payment of the principal of and interest and any premium on the Bonds will be secured by an assignment by the Issuer to the Trustee of the Issuer's interest in and to the Loan Agreement and all payments to be made pursuant thereto (other than certain indemnification and expense payments). Pursuant to the Loan Agreement, the Company will agree to pay, among other things, amounts sufficient to pay the aggregate principal amount of and premium, if any, on the Bonds, together with interest thereon as and when the same become due. The Company further will agree to make payments of the purchase price of the Bonds tendered for purchase to the extent that funds are not otherwise available therefor under the provisions of the Indenture.

The payment of the principal of and interest and any premium on the Bonds will be further secured by a separate tranche of the Company's First Mortgage Bonds, Collateral Series 2010 (the "First Mortgage Bonds") to be issued under an Indenture, dated as of October 1, 2010, as supplemented (the "First Mortgage Indenture"), between the Company and The Bank of New York Mellon, as trustee (the "First Mortgage Trustee"). The principal amount of the First Mortgage Bonds will equal the principal amount of the Bonds. If the Bonds become immediately due and payable as a result of a default in payment of the principal of, premium, if any, or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement and upon receipt by the First Mortgage Trustee of a written demand from the Trustee for redemption of the First Mortgage Bonds, or if all first mortgage bonds outstanding under the First Mortgage Indenture shall have been immediately due and payable, such First Mortgage Bonds will bear interest at the same interest rate or rates borne by the Bonds and the principal of such First Mortgage Bonds, together with interest accrued thereon from the last date or dates to which interest on the Bonds has been paid in full, will be payable in accordance with the Supplemental Indenture. See "Summary of the First Mortgage Bonds."

The First Mortgage Bonds are not intended to provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase in accordance with the Indenture. The First Mortgage Bonds are secured by a lien on certain property owned by the Company. In certain circumstances, the Company is permitted to reduce the aggregate principal amount of its First Mortgage Bonds held by the Trustee, but in no event to an amount lower than the aggregate outstanding principal amount of the Bonds.

* * * *

The sections of the Reoffering Circular captioned "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds"; " — Insurance"; " — Events of Default" and " — Remedies" are hereby added or amended, as applicable, to read in their entirety as follows:

Summary of the Loan Agreement

* * * *

Issuance and Delivery of First Mortgage Bonds

For the purpose of providing security for the Bonds, the Company will execute and deliver to the Trustee the First Mortgage Bonds. The principal amount of the First Mortgage Bonds executed and delivered to the Trustee will be equal to the aggregate principal amount of the Bonds. If the Bonds become immediately due and payable as a result of a default in payment of the principal of, premium, if any, or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement and upon receipt by the First Mortgage Trustee of a written demand from the Trustee for redemption of the First Mortgage Bonds, or if all first mortgage bonds outstanding under the First Mortgage Indenture shall have been immediately due and payable, such First Mortgage Bonds will bear interest at the same interest rate or rates borne by the Bonds and the principal of such First Mortgage Bonds, together with interest accrued thereon from the last date to which interest on the Bonds shall have been paid in full, will then be payable. See, however, "Summary of the Indenture — Waiver of Events of Default."

Upon payment of the principal of, premium, if any, and interest on any of the Bonds, and the surrender to and cancellation thereof by the Trustee, or upon provision for the payment thereof having been made in accordance with the Indenture, First Mortgage Bonds with corresponding principal amounts equal to the aggregate principal amount of the Bonds so surrendered and canceled or for the payment of which provision has been made, will be surrendered by the Trustee to the First Mortgage Trustee and will be canceled by the First Mortgage Trustee. The First Mortgage Bonds will be registered in the name of the Trustee and will be non transferable, except to effect transfers to any successor trustee under the Indenture.

Insurance

The Company has agreed to insure the Project in accordance with the provisions of the First Mortgage Indenture.

Events of Default

Each of the following events constitutes an "event of default" under the Loan Agreement:

(1) failure by the Company to pay the amounts required for payment of the principal of, including purchase price for tendered Bonds and redemption and acceleration prices, and interest accrued, on the Bonds, at the times specified therein taking into account any periods of grace provided in the Indenture and the Bonds for the applicable payment of interest on the Bonds (see "Summary of the Indenture — Defaults and Remedies");

(2) failure by the Company to observe and perform any covenant, condition or agreement, other than as referred to in paragraph (1) above, for a period of thirty days after written notice by the Issuer or Trustee, provided, however, that if such failure is capable of being corrected, but cannot be corrected in such 30-day period, it will not constitute an event of default under the Loan Agreement if corrective action with respect thereto is instituted within such period and is being diligently pursued;

(3) certain events of bankruptcy, dissolution, liquidation, reorganization or insolvency of the Company;

(4) the occurrence of an event of default under the Indenture; or

(5) all first mortgage bonds outstanding under the First Mortgage Indenture, if not already due, shall have become immediately due and payable, whether by declaration or otherwise, and such acceleration shall not have been rescinded or annulled by the First Mortgage Trustee.

Under the Loan Agreement, certain of the Company's obligations (other than the Company's obligations, among others, (i) not to permit any action which would result in interest paid on the Bonds being included in gross income for federal and Kentucky income taxes; (ii) to maintain its corporate existence and good standing, and to neither dispose of all or substantially all of its assets or consolidate with or merge into another corporation unless certain provisions of the Loan Agreement are satisfied; and (iii) to make loan payments and certain other payments under the provisions of the Loan Agreement) may be suspended if by reason of force majeure (as defined in the Loan Agreement) the Company is unable to carry out such obligations.

Remedies

Upon the happening of an event of default under the Loan Agreement, the Trustee, on behalf of the Issuer, may, among other things, take whatever action at law or in equity may appear necessary or desirable to collect the amounts then due and thereafter to become due, or to enforce performance and observance of any obligation, agreement or covenant of the Company, under the Loan Agreement, including any remedies available in respect of the First Mortgage Bonds.

In the event of a default in payment of the principal of, premium, if any, or interest on the Bonds and the acceleration of the maturity date of the Bonds (to the extent not already due and payable) as a consequence of such event of default, the Trustee may demand redemption of the First Mortgage Bonds. See "Summary of the First Mortgage Bonds" and "Summary of the Indenture — Defaults and Remedies." Any amounts collected upon the happening of any such event of default will be applied in accordance with the Indenture or, if the Bonds have been fully paid (or provision for payment thereof has been made in accordance with the Indenture) and all other liabilities of the Company accrued under the Indenture and the Loan Agreement have been paid or satisfied, made available to the Company.

* * * *

A new section is hereby added to the Reoffering Circular to read in its entirety as follows:

Summary of the First Mortgage Bonds

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the First Mortgage Bonds and the First Mortgage Indenture. This description is only a summary and does not purport to be complete and definitive. Reference is made to the First Mortgage Indenture and to the form of the First Mortgage Bonds for the detailed provisions thereof.

General

The First Mortgage Bonds, in a principal amount equal to the principal amount of the Bonds, were issued as a new tranche from a new series of first mortgage bonds under the First Mortgage Indenture (see "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds"). The statements herein made (being for the most part summaries of certain provisions of the First Mortgage Indenture) are subject to the detailed provisions of the First Mortgage Indenture, which is incorporated herein by this reference. Words or phrases italicized are defined in the First Mortgage Indenture.

The First Mortgage Bonds will mature on the same date and bear interest at the same rate or rates as the Bonds; however, the principal of and interest on the First Mortgage Bonds will not be payable other than upon the occurrence of an event of default under the Loan Agreement. If the Bonds become immediately due and payable as a result of a default in payment of the principal of, premium, if any, or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement, and if all first mortgage bonds outstanding under the First Mortgage Indenture shall not have become immediately due and payable following an event of default under the First Mortgage Indenture, the Company will be obligated to redeem the First Mortgage Bonds upon receipt by the First Mortgage Trustee of a Redemption Demand from the Trustee for redemption, at a redemption price equal to the principal amount thereof plus accrued interest at the rates borne by the Bonds from the last date to which interest on the Bonds has been paid.

The First Mortgage Bonds at all times will be in fully registered form registered in the name of the Trustee, will be non-negotiable, and will be non-transferable except to any successor trustee under the Indenture. Upon payment and cancellation of Bonds by the Trustee or the Paying Agent (other than any Bond or portion thereof that was canceled by the Trustee or the Paying Agent and for which one or more Bonds were delivered and authenticated pursuant to the Indenture), whether at maturity, by redemption or otherwise, or upon provision for the payment of the Bonds having been made in accordance with the Indenture, an equal principal amount of First Mortgage Bonds will be deemed fully paid and the obligations of the Company thereunder will cease.

Security; Lien of the First Mortgage Indenture

General. Except as described below under this heading and under "— Issuance of Additional First Mortgage Bonds," and subject to the exceptions described under "— Satisfaction and Discharge," all first mortgage bonds issued under the First Mortgage Indenture, including the Bonds, will be secured, equally and ratably, by the lien of the First Mortgage Indenture, which constitutes, subject to permitted liens as described below, a first mortgage lien on substantially all of the Company's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity (other than property duly released from the lien of the First Mortgage Indenture in accordance with the provisions thereof and other than excepted property, as described below). Property that is subject to the lien of the First Mortgage Indenture is referred to herein as "Mortgaged Property."

The Company may obtain the release of property from the lien of the First Mortgage Indenture from time to time, upon the bases provided for such release in the First Mortgage Indenture. See "— Release of Property."

The Company may enter into supplemental indentures with the First Mortgage Trustee, without the consent of the holders of the first mortgage bonds, in order to subject additional property (including property that would otherwise be excepted from such lien) to the lien of the First Mortgage Indenture. This property would constitute *property additions* and would be available as a basis for the issuance of additional first mortgage bonds. See "— Issuance of Additional First Mortgage Bonds."

The First Mortgage Indenture provides that after-acquired property (other than *excepted property*) will be subject to the lien of the First Mortgage Indenture. However, in the case of consolidation or merger (whether or not the Company is the surviving company) or transfer of the Mortgaged Property as or substantially as an entirety, the First Mortgage Indenture will not be required to be a lien upon any of the properties either owned or subsequently acquired by the successor company except properties acquired from the Company in or as a result of such transfer, as well as improvements, extensions and additions (as defined in the First Mortgage Indenture) to such properties and renewals, replacements and substitutions of or for any part or parts thereof. See "— Consolidation, Merger and Conveyance of Assets as an Entirety."

Excepted Property. The lien of the First Mortgage Indenture does not cover, among other things, the following types of property: property located outside of Kentucky and not specifically subjected or required to be subjected to the lien of the First Mortgage Indenture; property not used by the Company in its electric generation, transmission and distribution business; cash and securities not paid, deposited or held under the First Mortgage Indenture; contracts, leases and other agreements of all kinds, contract rights, bills, notes and other instruments, revenues, accounts receivable, claims, demands and judgments; governmental and other licenses, permits, franchises, consents and allowances; intellectual property rights and other general intangibles; vehicles, movable equipment, aircraft and vessels; all goods, stock in trade, wares, merchandise and inventory held for the purpose of sale or lease in the ordinary course of business; materials, supplies, inventory and other personal property consumable in the operation of the Company's business; fuel; tools and equipment; furniture and furnishings; computers and data processing, telecommunications and other facilities used primarily for administrative or clerical purposes or otherwise not used in connection with the operation or maintenance of electric generation, transmission and distribution facilities; coal, ore, gas, oil and other minerals and timber rights; electric energy and capacity, gas, steam, water and other products generated, produced, manufactured, purchased or otherwise acquired; real property and facilities used primarily for the production or gathering of natural gas; property which has been released from the lien of the First Mortgage Indenture; and leasehold interests. Property of the Company not covered by the lien of the First Mortgage Indenture is referred to herein as excepted property. Properties held by any of the Company's subsidiaries, as well as properties leased from others, would not be subject to the lien of the First Mortgage Indenture.

Permitted Liens. The lien of the First Mortgage Indenture is subject to permitted liens described in the First Mortgage Indenture. Such *permitted liens* include liens existing at the execution date of the First Mortgage Indenture, purchase money liens and other liens placed or otherwise existing on property acquired by the Company after the execution date of the First Mortgage Indenture at the time the Company acquires it, tax liens and other governmental charges which are not delinquent or which are being contested in good faith, mechanics', construction and materialmen's liens, certain judgment liens, easements, reservations and rights of others (including governmental entities) in, and defects of title to, the Company's property, certain leases and leasehold interests, liens to secure public obligations, rights of others to take minerals, timber, electric energy or capacity, gas, water, steam or other products produced by the Company or by others on the Company's property, rights and interests of persons other than the Company arising out of agreements relating to the common ownership or joint use of property, and liens on the interests of such persons in such property and liens which have been bonded or for which other security arrangements have been made.

The First Mortgage Indenture also provides that the First Mortgage Trustee will have a lien, prior to the lien on behalf of the holders of the first mortgage bonds, including the First Mortgage Bonds, upon the Mortgaged Property as security for the Company's payment of its reasonable compensation and expenses and for indemnity against certain liabilities. Any such lien would be a *permitted lien* under the First Mortgage Indenture.

Issuance of Additional First Mortgage Bonds

The maximum principal amount of first mortgage bonds that may be authenticated and delivered under the First Mortgage Indenture is subject to the issuance restrictions described below; provided, however, that the maximum principal amount of first mortgage bonds outstanding at any one time shall not exceed One Quintillion Dollars ($1,000,000,000,000,000,000), which amount may be changed by supplemental indenture. First mortgage bonds of any series may be issued from time to time on the basis of, and in an aggregate principal amount not exceeding:

- 66 2/3% of the *cost* or *fair value* to the Company (whichever is less) of *property additions* (as described below) which do not constitute *funded property* (generally, *property additions* which have been made the basis of the authentication and delivery of first mortgage bonds, the release of Mortgaged Property or the withdrawal of cash, which have been substituted for retired *funded property* or which have been used for other specified purposes) after certain deductions and additions, primarily including adjustments to offset property retirements;

- the aggregate principal amount of *retired securities* (as described below); or

- an amount of cash deposited with the First Mortgage Trustee.

Property additions generally include any property which is owned by the Company and is subject to the lien of the First Mortgage Indenture except (with certain exceptions) goodwill, going concern value rights or intangible property, or any property the acquisition or construction of which is properly chargeable to one of the Company's operating expense accounts.

Retired securities means, generally, first mortgage bonds which are no longer outstanding under the First Mortgage Indenture, which have not been retired by the application of *funded cash* and which have not been used as the basis for the authentication and delivery of first mortgage bonds, the release of property or the withdrawal of cash.

The First Mortgage Bonds will be issued on the basis of *property additions*. At August 31, 2010, approximately $2.3 billion of *property additions* were available to be used as the basis for the authentication and delivery of first mortgage bonds.

Release of Property

Unless an *event of default* has occurred and is continuing, the Company may obtain the release from the lien of the First Mortgage Indenture of any Mortgaged Property, except for cash held by the First Mortgage Trustee, upon delivery to the First Mortgage Trustee of an amount in cash equal to the amount, if any, by which sixty-six and two-thirds percent (66-2/3%) of the cost of the property to be released (or, if less, the *fair value* to the Company of such property at the time it became *funded property*) exceeds the aggregate of:

- an amount equal to 66 2/3% of the aggregate principal amount of obligations secured by *purchase money liens* upon the property to be released and delivered to the First Mortgage Trustee;

- an amount equal to 66 2/3% of the *cost* or *fair value* to the Company (whichever is less) of certified *property additions* not constituting *funded property* after certain deductions and additions, primarily including adjustments to offset property retirements (except that such adjustments need not be made if such *property additions* were acquired or made within the 90-day period preceding the release);

- the aggregate principal amount of first mortgage bonds the Company would be entitled to issue on the basis of *retired securities* (with such entitlement being waived by operation of such release);

- the aggregate principal amount of first mortgage bonds delivered to the First Mortgage Trustee (with such first mortgage bonds to be canceled by the First Mortgage Trustee);

- any amount of cash and/or an amount equal to 66 2/3% of the aggregate principal amount of obligations secured by *purchase money liens* upon the property released delivered to the trustee or other holder of a lien prior to the lien of the First Mortgage Indenture, subject to certain limitations described in the First Mortgage Indenture; and

- any taxes and expenses incidental to any sale, exchange, dedication or other disposition of the property to be released.

As used in the First Mortgage Indenture, the term *purchase money* lien means, generally, a lien on the property being released which is retained by the transferor of such property or granted to one or more other persons in connection with the transfer or release thereof, or granted to or held by a trustee or agent for any such persons, and may include liens which cover property in addition to the property being released and/or which secure indebtedness in addition to indebtedness to the transferor of such property.

Unless an *event of default* has occurred and is continuing, property which is not *funded property* may generally be released from the lien of the First Mortgage Indenture without depositing any cash or property with the First Mortgage Trustee as long as (a) the aggregate amount of *cost* or *fair value* to the Company (whichever is less) of all *property additions* which do not constitute *funded property* (excluding the property to be released) after certain deductions and additions, primarily including adjustments to offset property retirements, is not less than zero or (b) the cost or *fair value* (whichever is less) of property to be released does not exceed the aggregate amount of the cost or fair value to the Company (whichever is less) of *property additions* acquired or made within the 90-day period preceding the release.

The First Mortgage Indenture provides simplified procedures for the release of minor properties and property taken by eminent domain, and provides for dispositions of certain obsolete property and grants or surrender of certain rights without any release or consent by the First Mortgage Trustee.

If the Company retains any interest in any property released from the lien of the First Mortgage Indenture, the First Mortgage Indenture will not become a lien on such property or such interest therein or any improvements, extensions or additions to such property or renewals, replacements or substitutions of or for such property or any part or parts thereof.

Withdrawal of Cash

Unless an *event of default* has occurred and is continuing, and subject to certain limitations, cash held by the First Mortgage Trustee may, generally, (1) be withdrawn by the Company (a) to the extent of sixty-six and two-thirds percent (66-2/3%) of the cost or *fair value* to the Company (whichever is less) of *property additions* not constituting *funded property*, after certain deductions and additions, primarily including adjustments to offset retirements (except that such adjustments need not be made if such *property additions* were acquired or made within the 90-day period preceding the withdrawal) or (b) in an amount equal to the aggregate principal amount of first mortgage bonds that the Company would be entitled to issue on the basis of *retired securities* (with the entitlement to such issuance being waived by operation of such withdrawal) or (c) in an amount equal to the aggregate principal amount of any outstanding first mortgage bonds delivered to the First Mortgage Trustee; or (2) upon the Company’s request, be applied to (a) the purchase of first mortgage bonds in a manner and at a price approved by the Company or (b) the payment (or provision for payment) at stated maturity of any first mortgage bonds or the redemption (or provision for payment) of any first mortgage bonds which are redeemable; provided, however, that cash deposited with the First Mortgage Trustee as the basis for the authentication and delivery of first mortgage bonds may, in addition, be withdrawn in an amount not exceeding the aggregate principal amount of cash delivered to the First Mortgage Trustee for such purpose.

Events of Default

An "*event of default*" occurs under the First Mortgage Indenture if

- the Company does not pay any interest on any first mortgage bonds within 30 days of the due date;

- the Company does not pay principal or premium, if any, on any first mortgage bonds on the due date;

- the Company remains in breach of any other covenant (excluding covenants specifically dealt with elsewhere in this section) in respect of any first mortgage bonds for 90 days after the Company receives a written notice of default stating the Company is in breach and requiring remedy of the breach; the notice must be sent by either the First Mortgage Trustee or holders of 25% of the principal amount of outstanding first mortgage bonds; the First Mortgage Trustee or such holders can agree to extend the 90-day period and such an agreement to extend will be automatically deemed to occur if the Company initiates corrective action within such 90 day period and the Company is diligently pursuing such action to correct the default; or

- the Company files for bankruptcy or certain other events in bankruptcy, insolvency, receivership or reorganization occur.

Remedies

Acceleration of Maturity. If an event of default occurs and is continuing, then either the First Mortgage Trustee or the holders of not less than 25% in principal amount of the outstanding first mortgage bonds may declare the principal amount of all of the first mortgage bonds to be due and payable immediately.

Rescission of Acceleration. After the declaration of acceleration has been made and before the First Mortgage Trustee has obtained a judgment or decree for payment of the money due, such declaration and its consequences will be rescinded and annulled, if

- the Company pays or deposits with the First Mortgage Trustee a sum sufficient to pay:

    - all overdue interest;

    - the principal of and premium, if any, which have become due otherwise than by such declaration of acceleration and interest thereon;

    - interest on overdue interest to the extent lawful;

- all amounts due to the First Mortgage Trustee under the First Mortgage Indenture; and

- all *events of default*, other than the nonpayment of the principal which has become due solely by such declaration of acceleration, have been cured or waived as provided in the First Mortgage Indenture.

For more information as to waiver of defaults, see "— Waiver of Default and of Compliance" below.

Appointment of Receiver and Other Remedies. Subject to the First Mortgage Indenture, under certain circumstances and to the extent permitted by law, if an *event of default* occurs and is continuing, the First Mortgage Trustee has the power to appoint a receiver of the Mortgaged Property, and is entitled to all other remedies available to mortgagees and secured parties under the Uniform Commercial Code or any other applicable law.

Control by Holders; Limitations. Subject to the First Mortgage Indenture, if an *event of default* occurs and is continuing, the holders of a majority in principal amount of the outstanding first mortgage bonds will have the right to

- direct the time, method and place of conducting any proceeding for any remedy available to the First Mortgage Trustee, or

- exercise any trust or power conferred on the First Mortgage Trustee.

The rights of holders to make direction are subject to the following limitations:

- the holders' directions may not conflict with any law or the First Mortgage Indenture; and

- the holders' directions may not involve the First Mortgage Trustee in personal liability where the First Mortgage Trustee believes indemnity is not adequate.

The First Mortgage Trustee may also take any other action it deems proper which is not inconsistent with the holders' direction.

In addition, the First Mortgage Indenture provides that no holder of any first mortgage bond will have any right to institute any proceeding, judicial or otherwise, with respect to the First Mortgage Indenture for the appointment of a receiver or for any other remedy thereunder unless

- that holder has previously given the First Mortgage Trustee written notice of a continuing *event of default*;

- the holders of 25% in aggregate principal amount of the outstanding first mortgage bonds have made written request to the First Mortgage Trustee to institute proceedings in respect of that *event of default* and have offered the First Mortgage Trustee reasonable indemnity against costs, expenses and liabilities incurred in complying with such request; and

- for 60 days after receipt of such notice, request and offer of indemnity, the First Mortgage Trustee has failed to institute any such proceeding and no direction inconsistent with such request has been given to the First Mortgage Trustee during such 60-day period by the holders of a majority in aggregate principal amount of outstanding first mortgage bonds.

Furthermore, no holder of any first mortgage bonds will be entitled to institute any such action if and to the extent that such action would disturb or prejudice the rights of other holders of first mortgage bonds.

However, each holder of any first mortgage bonds has an absolute and unconditional right to receive payment when due and to bring a suit to enforce that right.

Notice of Default. The First Mortgage Trustee is required to give the holders of the first mortgage bonds notice of any default under the First Mortgage Indenture to the extent required by the Trust Indenture Act, unless such default has been cured or waived; except that in the case of an *event of default* of the character specified in the third bullet point under "— Events of Default" (regarding a breach of certain covenants continuing for 90 days after the receipt of a written notice of default), no such notice shall be given to such holders until at least 60 days after the occurrence thereof. The Trust Indenture Act currently permits the First Mortgage Trustee to withhold notices of default (except for certain payment defaults) if the First Mortgage Trustee in good faith determines the withholding of such notice to be in the interests of the holders of the first mortgage bonds.

The Company will furnish the First Mortgage Trustee with an annual statement as to its compliance with the conditions and covenants in the First Mortgage Indenture.

Waiver of Default and of Compliance. The holders of a majority in aggregate principal amount of the outstanding first mortgage bonds may waive, on behalf of the holders of all outstanding first mortgage bonds, any past default under the First Mortgage Indenture, except a default in the payment of principal, premium or interest, or with respect to compliance with certain provisions of the First Mortgage Indenture that cannot be amended without the consent of the holder of each outstanding first mortgage bond affected.

Compliance with certain covenants in the First Mortgage Indenture or otherwise provided with respect to first mortgage bonds may be waived by the holders of a majority in aggregate principal amount of the affected first mortgage bonds, considered as one class.

Consolidation, Merger and Conveyance of Assets as an Entirety

Subject to the provisions described below, the Company has agreed to preserve its corporate existence.

The Company has agreed not to consolidate with or merge with or into any other entity or convey, transfer or lease the Mortgaged Property as or substantially as an entirety to any entity unless

- the entity formed by such consolidation or into which the Company merges, or the entity which acquires or which leases the Mortgaged Property substantially as an entirety, is an entity organized and existing under the laws of the United States of America or any State or Territory thereof or the District of Columbia, and

- expressly assumes, by supplemental indenture, the due and punctual payment of the principal of, and premium and interest on, all the outstanding first mortgage bonds and the performance of all of the Company's covenants under the First Mortgage Indenture, and

- such entity confirms the lien of the First Mortgage Indenture on the Mortgaged Property, including property thereafter acquired by such entity which constitutes an improvement, extension or addition to the Mortgaged Property or a renewal, replacement or substitution thereof;

- in the case of a lease, such lease is made expressly subject to termination by (i) the Company or by the First Mortgage Trustee and (ii) the purchaser of the property so leased at any sale thereof, at any time during the continuance of an *event of default*; and

- immediately after giving effect to such transaction, no *event of default*, and no event which after notice or lapse of time or both would become an *event of default*, will have occurred and be continuing.

In the case of the conveyance or other transfer of the Mortgaged Property as or substantially as an entirety to any other person, upon the satisfaction of all the conditions described above the Company would be released and discharged from all obligations under the First Mortgage Indenture and on the first mortgage bonds then outstanding unless the Company elects to waive such release and discharge.

The First Mortgage Indenture does not prevent or restrict:

- any consolidation or merger after the consummation of which the Company would be the surviving or resulting entity; or

- any conveyance or other transfer, or lease, of any part of the Mortgaged Property which does not constitute the entirety or substantially the entirety thereof.

If following a conveyance or other transfer, or lease, of any part of the Mortgaged Property, the fair value of the Mortgaged Property retained by the Company exceeds an amount equal to three-halves (3/2) of the aggregate principal amount of all outstanding first mortgage bonds, then the part of the Mortgaged Property so conveyed, transferred or leased shall be deemed not to constitute the entirety or substantially the entirety of the Mortgaged Property. This fair value will be determined within 90 days of the conveyance or transfer by an independent expert that the Company selects and that is approved by the First Mortgage Trustee.

Modification of First Mortgage Indenture

Without Holder Consent. Without the consent of any holders of first mortgage bonds, the Company and the First Mortgage Trustee may enter into one or more supplemental indentures for any of the following purposes:

- to evidence the succession of another entity to the Company;
- to add one or more covenants or other provisions for the benefit of the holders of all or any series or tranche of first mortgage bonds, or to surrender any right or power conferred upon the Company;
- to correct or amplify the description of any property at any time subject to the lien of the First Mortgage Indenture; or to better assure, convey and confirm unto the First Mortgage Trustee any property subject or required to be subjected to the lien of the First Mortgage Indenture; or to subject to the lien of the First Mortgage Indenture additional property (including property of others), to specify any additional Permitted Liens with respect to such additional property and to modify the provisions in the First Mortgage Indenture for dispositions of certain types of property without release in order to specify any additional items with respect to such additional property;
- to add any additional e*vents of default*, which may be stated to remain in effect only so long as the first mortgage bonds of any one more particular series remains outstanding;
- to change or eliminate any provision of the First Mortgage Indenture or to add any new provision to the First Mortgage Indenture that does not adversely affect the interests of the holders in any material respect;
- to establish the form or terms of any series or tranche of first mortgage bonds;
- to provide for the issuance of bearer securities;
- to evidence and provide for the acceptance of appointment of a successor First Mortgage Trustee or by a co-trustee or separate trustee;
- to provide for the procedures required to permit the utilization of a noncertificated system of registration for any series or tranche of first mortgage bonds;
- to change any place or places where
    - the Company may pay principal, premium and interest,
    - first mortgage bonds may be surrendered for transfer or exchange, and
    - notices and demands to or upon the Company may be served;

- to amend and restate the First Mortgage Indenture as originally executed, and as amended from time to time, with such additions, deletions and other changes that do not adversely affect the interest of the holders in any material respect;

- to cure any ambiguity, defect or inconsistency or to make any other changes that do not adversely affect the interests of the holders in any material respect; or

- to increase or decrease the maximum principal amount of first mortgage bonds that may be outstanding at any time.

In addition, if the Trust Indenture Act is amended after the date of the First Mortgage Indenture so as to require changes to the First Mortgage Indenture or so as to permit changes to, or the elimination of, provisions which, at the date of the First Mortgage Indenture or at any time thereafter, were required by the Trust Indenture Act to be contained in the First Mortgage Indenture, the First Mortgage Indenture will be deemed to have been amended so as to conform to such amendment or to effect such changes or elimination, and the Company and the First Mortgage Trustee may, without the consent of any holders, enter into one or more supplemental indentures to effect or evidence such amendment.

With Holder Consent. Except as provided above, the consent of the holders of at least a majority in aggregate principal amount of the first mortgage bonds of all outstanding series, considered as one class, is generally required for the purpose of adding to, or changing or eliminating any of the provisions of, the First Mortgage Indenture pursuant to a supplemental indenture. However, if less than all of the series of outstanding first mortgage bonds are directly affected by a proposed supplemental indenture, then such proposal only requires the consent of the holders of a majority in aggregate principal amount of the outstanding first mortgage bonds of all directly affected series, considered as one class. Moreover, if the first mortgage bonds of any series have been issued in more than one tranche and if the proposed supplemental indenture directly affects the rights of the holders of first mortgage bonds of one or more, but less than all, of such tranches, then such proposal only requires the consent of the holders of a majority in aggregate principal amount of the outstanding first mortgage bonds of all directly affected tranches, considered as one class.

However, no amendment or modification may, without the consent of the holder of each outstanding first mortgage bond directly affected thereby,

- change the stated maturity of the principal or interest on any first mortgage bond (other than pursuant to the terms thereof), or reduce the principal amount, interest or premium payable (or method of calculating such rates)or change the currency in which any first mortgage bond is payable, or impair the right to bring suit to enforce any payment;

- create any lien (not otherwise permitted by the First Mortgage Indenture) ranking prior to the lien of the First Mortgage Indenture with respect to all or substantially all of the Mortgaged Property, or terminate the lien of the First Mortgage Indenture on all or substantially all of the Mortgaged Property (other than in accordance with the terms of the First Mortgage Indenture), or deprive any holder of the benefits of the security of the lien of the First Mortgage Indenture;

- reduce the percentages of holders whose consent is required for any supplemental indenture or waiver of compliance with any provision of the First Mortgage Indenture or of any default thereunder and its consequences, or reduce the requirements for quorum and voting under the First Mortgage Indenture; or

- modify certain of the provisions of the First Mortgage Indenture relating to supplemental indentures, waivers of certain covenants and waivers of past defaults with respect to first mortgage bonds.

A supplemental indenture which changes, modifies or eliminates any provision of the First Mortgage Indenture expressly included solely for the benefit of holders of first mortgage bonds of one or more particular series or tranches will be deemed not to affect the rights under the First Mortgage Indenture of the holders of first mortgage bonds of any other series or tranche.

Satisfaction and Discharge

Any first mortgage bonds or any portion thereof will be deemed to have been paid and no longer outstanding for purposes of the First Mortgage Indenture and, at the Company's election, the Company's entire indebtedness with respect to those securities will be satisfied and discharged, if there shall have been irrevocably deposited with the First Mortgage Trustee or any Paying Agent (other than the Company), in trust:

- money sufficient, or

- in the case of a deposit made prior to the maturity of such first mortgage bonds, non-redeemable *eligible obligations* (as defined in the First Mortgage Indenture) sufficient, or

- a combination of the items listed in the preceding two bullet points, which in total are sufficient,

to pay when due the principal of, and any premium, and interest due and to become due on such first mortgage bonds or portions of such first mortgage bonds on and prior to their maturity.

The Company's right to cause its entire indebtedness in respect of the first mortgage bonds of any series to be deemed to be satisfied and discharged as described above will be subject to the satisfaction of any conditions specified in the instrument creating such series.

The First Mortgage Indenture will be deemed satisfied and discharged when no first mortgage bonds remain outstanding and when the Company has paid all other sums payable by it under the First Mortgage Indenture.

All moneys the Company pays to the First Mortgage Trustee or any Paying Agent on First Mortgage Bonds that remain unclaimed at the end of two years after payments have become due may be paid to or upon the Company's order. Thereafter, the holder of such First Mortgage Bond may look only to the Company for payment.

Duties of the First Mortgage Trustee; Resignation and Removal of the First Mortgage Trustee; Deemed Resignation

The First Mortgage Trustee will have, and will be subject to, all the duties and responsibilities specified with respect to an indenture trustee under the Trust Indenture Act. Subject to these provisions, the First Mortgage Trustee will be under no obligation to exercise any of the powers vested in it by the First Mortgage Indenture at the request of any holder of first mortgage bonds, unless offered reasonable indemnity by such holder against the costs, expenses and liabilities which might be incurred thereby. The First Mortgage Trustee will not be required to expend or risk its own funds or otherwise incur financial liability in the performance of its duties if the First Mortgage Trustee reasonably believes that repayment or adequate indemnity is not reasonably assured to it.

The First Mortgage Trustee may resign at any time by giving written notice to the Company.

The First Mortgage Trustee may also be removed by act of the holders of a majority in principal amount of the then outstanding first mortgage bonds of any series.

No resignation or removal of the First Mortgage Trustee and no appointment of a successor trustee will become effective until the acceptance of appointment by a successor trustee in accordance with the requirements of the First Mortgage Indenture.

Under certain circumstances, the Company may appoint a successor trustee and if the successor accepts, the First Mortgage Trustee will be deemed to have resigned.

Evidence to be Furnished to the First Mortgage Trustee

Compliance with First Mortgage Indenture provisions is evidenced by written statements of the Company's officers or persons selected or paid by the Company. In certain cases, opinions of counsel and certifications of an engineer, accountant, appraiser or other expert (who in some cases must be independent) must be furnished. In addition, the First Mortgage Indenture requires the Company to give to the First Mortgage Trustee, not less than annually, a brief statement as to the Company's compliance with the conditions and covenants under the First Mortgage Indenture.

Miscellaneous Provisions

The First Mortgage Indenture provides that certain first mortgage bonds, including those for which payment or redemption money has been deposited or set aside in trust as described under "— Satisfaction and Discharge" above, will not be deemed to be "outstanding" in determining whether the holders of the requisite principal amount of the outstanding first mortgage bonds have given or taken any demand, direction, consent or other action under the First Mortgage Indenture as of any date, or are present at a meeting of holders for quorum purposes.

The Company will be entitled to set any day as a record date for the purpose of determining the holders of outstanding first mortgage bonds of any series entitled to give or take any demand, direction, consent or other action under the First Mortgage Indenture, in the manner and subject to the limitations provided in the First Mortgage Indenture. In certain circumstances, the First Mortgage Trustee also will be entitled to set a record date for action by holders. If such a record date is set for any action to be taken by holders of particular first mortgage bonds, such action may be taken only by persons who are holders of such first mortgage bonds on the record date.

Governing Law

The First Mortgage Indenture and the first mortgage bonds provide that they are to be governed by and construed in accordance with the laws of the State of New York except where the Trust Indenture Act is applicable or where otherwise required by law. The effectiveness of the lien of the First Mortgage Indenture, and the perfection and priority thereof, will be governed by Kentucky law.

* * * *

The sections of the Reoffering Circular captioned "Summary of the Indenture — Surrender of First Mortgage Bonds"; "— Defaults and Remedies"; "— Waiver of Events of Default"; and "— Voting of First Mortgage Bonds Held by Trustee" are hereby added or amended, as applicable, to read in their entirety as follows:

Summary of the Indenture

* * * *

Surrender of First Mortgage Bonds

Upon payment of any principal of, premium, if any, and interest on any of the Bonds which reduces the principal amount of Bonds outstanding, or upon provision for the payment thereof having been made in accordance with the Indenture, First Mortgage Bonds in a principal amount equal to the principal amount of the Bonds so paid, or for the payment of which such provision has been made, shall be surrendered by the Trustee to the First Mortgage Trustee. The First Mortgage Bonds so surrendered shall be deemed fully paid and the obligations of the Company thereunder terminated.

Defaults and Remedies

Each of the following events constitutes an "Event of Default" under the Indenture:

(1) failure to make payment of any installment of interest on any Bond, (a) if such Bond bears interest at other than the Long Term Rate, within a period of one Business Day from the due date and (b) if such Bond bears interest at the Long Term Rate, within a period of five Business Days from the due date;

(2) failure to make punctual payment of the principal of, or premium, if any, on any Bond on the due date, whether at the stated maturity thereof, or upon proceedings for redemption, or upon the maturity thereof by declaration or if payment of the purchase price of any Bond required to be purchased pursuant to the Indenture is not made when such payment has become due and payable;

(3) failure of the Issuer to perform or observe any other of the covenants, agreements or conditions in the Indenture or in the Bonds which failure continues for a period of 30 days after written notice by the Trustee, provided, however, that if such failure is capable of being cured, but cannot be cured in such 30-day period, it will not constitute an event of default under the Indenture if corrective action in respect of such failure is instituted within such 30-day period and is being diligently pursued;

(4) the occurrence of an "event of default" under the Loan Agreement (see "Summary of the Loan Agreement — Events of Default");

(5) written notice from the Credit Facility Issuer to the Trustee of an event of default under the Reimbursement Agreement, by reason of which the Trustee has been directed to accelerate the Bonds;

(6) if a Credit Facility is then held by the Trustee, on or before the close of business on the tenth calendar day following the honoring of a drawing under such Credit Facility to pay interest on the Bonds on an Interest Payment Date, written notice from the Credit Facility Issuer to the Trustee that the interest component of the Credit Facility will not be reinstated; or

(7) all first mortgage bonds outstanding under the First Mortgage Indenture, if not already due, shall have become due and payable, whether by declaration or otherwise, and such acceleration shall not have been rescinded by the First Mortgage Trustee.

Upon the occurrence of an Event of Default under clauses (1), (2), (5), (6) or (7) above, the Trustee must: (i) enforce each and every right granted to the Trustee as a holder of the First Mortgage Bonds (see "Summary of the First Mortgage Bonds"), (ii) declare the principal of all Bonds and interest accrued thereon to be immediately due and payable, (iii) declare all payments under the Loan Agreement to be immediately due and payable and enforce each and every other right granted to the Issuer under the Loan Agreement for the benefit of the Bondholders and (iv) if a Credit Facility securing the Bonds is in effect, make an immediate drawing under the Credit Facility in accordance with its terms and deposit the proceeds of such drawing in the Bond Fund pending application to the payment of principal of the Bonds, subject to the provisions of the Indenture reserving to the Credit Facility Issuer the right to direct default proceedings and providing for termination of default proceedings upon certain occurrences.

Interest on the Bonds will cease to accrue on the date of issuance of the declaration of acceleration of payment of principal and interest on the Bonds.

In exercising such rights, the Trustee shall take any action that, in the judgment of the Trustee, would best serve the interests of the registered owners. Upon the occurrence of an Event of Default under the Indenture, the Trustee may also proceed to pursue any available remedy by suit at law or in equity to enforce the payment of the principal of, premium, if any, and interest on the Bonds then outstanding.

If an Event of Default under the Indenture shall occur and be continuing and the maturity date of the Bonds has been accelerated (to the extent the Bonds are not already due and payable) as a consequence of such event of default, the Trustee may, and upon the written request of the registered owners holding not less than 25% in principal amount of all Bonds then outstanding and upon receipt of indemnity satisfactory to it shall, exercise such rights as it shall possess under the First Mortgage Indenture as a holder of the First Mortgage Bonds and shall also issue a Redemption Demand for such First Mortgage Bonds to the First Mortgage Trustee.

If the Trustee recovers any moneys following an Event of Default, unless the principal of the Bonds shall have been declared due and payable, all such moneys shall be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent, (ii) to the payment of all interest then due on the Bonds and (iii) to the payment of unpaid principal and premium, if any, of the Bonds. If the principal of the Bonds has become due or has been accelerated, such moneys shall be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and (ii) to the payment of principal of and interest then due and unpaid on the Bonds. In each case, however, Trustee and Paying Agent fees or costs will not be payable from moneys derived from Credit Facility drawings, any remarketing proceeds or moneys constituting certain Available Moneys under the Indenture.

No Bondholder may institute any suit or proceeding in equity or at law for the enforcement of the Indenture unless an Event of Default has occurred of which the Trustee has been notified or is deemed to have notice, and registered owners holding not less than 25% in aggregate principal amount of Bonds then outstanding shall have made written request to the Trustee to proceed to exercise the powers granted under the Indenture or to institute such action in their own name and the Trustee shall fail or refuse to exercise its powers within a reasonable time after receipt of indemnity satisfactory to it.

Any judgment against the Issuer pursuant to the exercise of rights under the Indenture shall be enforceable only against specific assigned payments, funds and accounts under the Indenture in the hands of the Trustee. No deficiency judgment shall be authorized against the general credit of the Issuer.

No default under paragraph (3) above shall constitute an Event of Default until actual notice is given to the Issuer and the Company by the Trustee or to the Issuer, the Company and the Trustee by the registered owners holding not less than 25% in aggregate principal amount of all Bonds outstanding and the Issuer and the Company shall have had thirty days after such notice to correct the default and failed to do so. If the default is such that it cannot be corrected within the applicable period but is capable of being cured, it will not constitute an Event of Default if corrective action is instituted within the applicable period.

Notwithstanding the foregoing, in addition to the rights of the Trustee and the Bondholders to direct proceedings as described above, if a Credit Facility is in effect, for so long as such Credit Facility is outstanding and the Credit Facility Issuer is not in default in its duties under the Indenture or the Credit Facility, the Credit Facility Issuer will have the absolute right to direct all proceedings on behalf of the Bondholders of the Bonds. Additionally, if the Event of Default which has occurred is an Event of Default under paragraphs (5) or (6) above, the Credit Facility Issuer, if any, will have no right to direct the Trustee or the Bondholders with respect to any matters, including remedies, and the holders of a majority in aggregate principal amount of the Bonds then outstanding, will have the right, at any time, by an instrument or instruments in writing executed and delivered to the Trustee, to direct the time, method and place of conducting all proceedings to be taken in connection with the enforcement of the terms and conditions of the Indenture, or for the appointment of a receiver or any other proceedings hereunder; provided, that such direction shall not be otherwise than in accordance with the provisions of law and of the Indenture.

If an Event of Default has occurred under the Indenture due to failure by the Credit Facility Issuer, if any, to honor a properly presented and conforming drawing by the Trustee under the Credit Facility then in effect in accordance with the terms thereof, all obligations of the Trustee to the Credit Facility Issuer and all rights of such Credit Facility Issuer under the Indenture will be suspended until the earlier of the cure of such failure or all of the Bonds have been paid in full.

Waiver of Events of Default

Except as provided below, the Trustee may in its discretion waive any Event of Default under the Indenture and shall do so upon the written request of the registered owners holding a majority in principal amount of all Bonds then outstanding. If, after the principal of all Bonds then outstanding shall have been declared to be due and payable and prior to any judgment or decree for the appointment of a receiver or for the payment of the moneys due shall have been entered, (i) the Company has caused to be deposited with the Trustee a sum sufficient to pay all matured installments of interest upon all Bonds and the principal of and premium, if any, on any and all Bonds which shall have become due otherwise than by reason of such declaration and the expenses of the Trustee in connection with such default (with interest thereon as provided in the Indenture) and (ii) all Events of Default under the Indenture (other than nonpayment of the principal of Bonds due by said declaration) shall have been remedied, then such Event of Default shall be deemed waived and such declaration and its consequences rescinded and annulled by the Trustee. Such waiver, rescission and annulment shall be binding upon all Bondholders. No such waiver, rescission and annulment shall extend to or affect any subsequent Event of Default or impair any right or remedy consequent thereon.

Upon any waiver or rescission as described above or any discontinuance or abandonment of proceedings under the Indenture, the Trustee shall immediately rescind in writing any Redemption Demand of First Mortgage Bonds previously given to the First Mortgage Trustee. The rescission under the First Mortgage Indenture of a declaration that all first mortgage bonds outstanding under the First Mortgage Indenture are immediately due and payable shall also constitute a waiver of an Event of Default described in paragraph (6) under the subcaption "—Defaults and Remedies" above and a waiver and rescission of its consequences, provided that no such waiver or rescission shall extend to or affect any subsequent or other default or impair any right consequent thereon.

The Trustee may not waive any default under clauses (5) or (6) above unless the Trustee has received in writing from the Credit Facility Issuer a written notice of full reinstatement of the full amount of the Credit Facility and a written rescission of the notice of the Event of Default.

Notwithstanding the foregoing, nothing in the Indenture shall affect the right of a registered owner to enforce the payment of principal of, premium, if any, and interest on the Bonds after the maturity thereof.

Voting of First Mortgage Bonds Held by Trustee

The Trustee, as holder of the First Mortgage Bonds, shall attend any meeting of holders of first mortgage bonds outstanding under the First Mortgage Indenture as to which it receives due notice. The Trustee shall vote the First Mortgage Bonds held by it, or shall consent with respect thereto, proportionally in the way in which the Trustee reasonably believes will be the vote or consent of all other holders of first mortgage bonds outstanding under the First Mortgage Indenture then eligible to vote or consent.

Notwithstanding the foregoing, the Trustee may not vote the First Mortgage Bonds in favor of, or give consent to, any action which, in the Trustee's opinion, would materially adversely affect the First Mortgage Bonds in a manner not generally shared by all other series of first mortgage bonds, except upon notification by the Trustee to the registered owners of all Bonds then outstanding of such proposal and consent thereto of the registered owners of at least 66 2/3% in aggregate principal amount of all Bonds then outstanding.

NOT A NEW ISSUE *BOOK-ENTRY-ONLY*

On May 19, 2000, the date on which the Bonds were originally issued, Bond Counsel delivered its opinion that stated that, subject to the conditions and exceptions set forth under the caption "Tax Treatment," under then current law, interest on the Bonds would be excludable from the gross income of the recipients thereof for federal income tax purposes, except that no opinion was expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" or a "related person" of the Project as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on the Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. Such interest may be subject to certain federal income taxes imposed on certain corporations, including imposition of the branch profits tax on a portion of such interest. Bond Counsel was further of the opinion that interest on the Bonds would be excludable from the gross income of the recipients thereof for Kentucky income tax purposes and that, under then current law, the principal of the Bonds would be exempt from ad valorem taxes in Kentucky. Such opinion has not been updated as of the date hereof and no continuing tax exemption opinions are expressed by Bond Counsel. However, in connection with the reoffering of the Bonds, as described herein, Bond Counsel will deliver its opinion to the effect that the delivery of a letter of credit (a) is authorized or permitted by the Act and the Indenture and (b) will not adversely affect the validity of the Bonds or any exclusion of the interest thereon from the gross income of the owners of the Bonds for federal income tax purposes. See "Tax Treatment" herein.

$12,900,000
County of Mercer, Kentucky,
Solid Waste Disposal Facility Revenue Bonds,
2000 Series A
(Kentucky Utilities Company Project)
Due: May 1, 2023

Reoffering Date: December 17, 2008

The County of Mercer, Kentucky, Solid Waste Disposal Facility Revenue Bonds, 2000 Series A (Kentucky Utilities Company Project) (the "Bonds") are special and limited obligations of the County of Mercer, Kentucky (the "Issuer"), payable by the Issuer solely from and secured by payments to be received by the Issuer pursuant to a Loan Agreement with

Kentucky Utilities Company

(the "Company"), except as payable from proceeds of such Bonds or investment earnings thereon. The Bonds do not constitute general obligations of the Issuer or a charge against the general credit or taxing powers thereof or of the Commonwealth of Kentucky or any other political subdivision of Kentucky. The Bonds are not entitled to the benefits of any financial guaranty insurance policies.

The Bonds were originally issued on May 19, 2000 and currently bear interest at a Weekly Rate. Pursuant to the Indenture under which the Bonds were issued, the Company has elected to deliver a letter of credit to the Trustee and reoffer the Bonds. The Bonds are subject to mandatory purchase on the Reoffering Date and are being reoffered by this Reoffering Circular. Morgan Stanley & Co. Incorporated will serve as the Remarketing Agent for the Bonds.

From the Reoffering Date through December 16, 2009 (the Letter of Credit (as defined below) expiration date, subject to extension or earlier termination), payment of the principal of and interest on the Bonds when due will be paid with funds drawn under an irrevocable transferable direct pay letter of credit (the "Letter of Credit") issued by

Commerzbank AG, New York Branch

The Letter of Credit will permit the Trustee to draw with respect to the Bonds up to an amount sufficient to pay (i) the principal thereof (or that portion of the purchase price corresponding to principal) plus (ii) interest thereon (or that portion of the purchase price corresponding to interest) at an assumed rate of 10% per annum for at least 45 days.

From and after the Reoffering Date, the Bonds will continue to bear interest at a Weekly Rate, determined by the Remarketing Agent in accordance with the Indenture, payable on the first Business Day of each calendar month, commencing on January 2, 2009. The interest rate period, interest rate and Interest Rate Mode will be subject to change under certain conditions, as described in this Reoffering Circular. The Bonds are subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption following a determination of taxability prior to maturity, as described in this Reoffering Circular. The Bonds are subject to mandatory purchase on any date on which the Bonds are converted to a different Interest Rate Mode and upon the expiration of the Letter of Credit or any Alternate Credit Facility.

The Bonds are registered in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company ("DTC"), New York, New York. DTC will act as securities depository. Except as described in this Reoffering Circular, purchases of beneficial ownership interests in the Bonds will be made in book-entry-only form in denominations of $100,000 and multiples thereof. Purchasers will not receive certificates representing their beneficial interest in the Bonds. See the information contained under the caption "Summary of the Bonds—Book-Entry-Only System" in this Reoffering Circular. The principal of, premium, if any, and interest on the Bonds will be paid by The Bank of New York Mellon, as Trustee, to Cede & Co., as long as Cede & Co. is the registered owner of the Bonds. Disbursement of such payments to the DTC Participants is the responsibility of DTC, and disbursement of such payments to the purchasers of beneficial ownership interests is the responsibility of DTC's Direct and Indirect Participants, as more fully described in this Reoffering Circular.

PRICE: 100%

The Bonds are reoffered subject to prior sale, withdrawal or modification of the offer without notice (provided, however, that any such notice of withdrawal must be given on the Business Day prior to the Reoffering Date) and to the approval of legality by Stoll Keenon Ogden PLLC, Louisville, Kentucky, as Bond Counsel, and upon satisfaction of certain conditions. Certain legal matters will be passed upon for the Company by its counsel, Jones Day, Chicago, Illinois, and John R. McCall, Esq., Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer of the Company, for the Issuer by its County Attorney, and for the Remarketing Agent by its counsel, Winston & Strawn LLP, Chicago, Illinois. It is expected that the Bonds will be available for redelivery to DTC in New York, New York on or about December 17, 2008.

MORGAN STANLEY

Dated: December 10, 2008

No dealer, broker, salesman or other person has been authorized by the Issuer, the Company or the Remarketing Agent to give any information or to make any representation with respect to the Bonds, other than those contained in this Reoffering Circular, and, if given or made, such other information or representation must not be relied upon as having been authorized by any of the foregoing. The Remarketing Agent has provided the following sentence for inclusion in this Reoffering Circular. The Remarketing Agent has reviewed the information in this Reoffering Circular in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Remarketing Agent does not guarantee the accuracy or completeness of such information. The information and expressions of opinion herein are subject to change without notice, and neither the delivery of this Reoffering Circular nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the parties referred to above since the date hereof. The information set forth herein with respect to the Issuer has been obtained from the Issuer, and all other information has been obtained from the Company and from other sources that are believed to be reliable, but it is not guaranteed as to accuracy or completeness by, and is not to be construed as a representation by, the Remarketing Agent.

In connection with the reoffering of the Bonds, the Remarketing Agent may over-allot or effect transactions which stabilize or maintain the market prices of the Bonds at levels above those that might otherwise prevail in the open market. Such stabilizing, if commenced, may be discontinued at any time.

IN MAKING AN INVESTMENT DECISION, INVESTORS MUST RELY ON THEIR OWN EXAMINATION OF THE TERMS OF THE REOFFERING, INCLUDING THE MERITS AND RISKS INVOLVED. THESE SECURITIES HAVE NOT BEEN RECOMMENDED BY ANY FEDERAL OR STATE SECURITIES COMMISSION OR REGULATORY AUTHORITY. FURTHERMORE, THE FOREGOING AUTHORITIES HAVE NOT CONFIRMED THE ACCURACY OR DETERMINED THE ADEQUACY OF THIS DOCUMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

Table of Contents

$12,900,000
County of Mercer, Kentucky
Solid Waste Disposal Facility Revenue Bonds,
2000 Series A
(Kentucky Utilities Company Project)
Due: May 1, 2023

Introductory Statement

This Reoffering Circular, including the cover page and appendices, is provided to furnish information in connection with the reoffering by the County of Mercer, Kentucky (the "Issuer") of its Solid Waste Disposal Facility Revenue Bonds, 2000 Series A (Kentucky Utilities Company Project), in the aggregate principal amount of $12,900,000 (the "Bonds") issued on May 19, 2000 pursuant to an Indenture of Trust dated as of May 1, 2000 (the "Indenture") between the Issuer and The Bank of New York Mellon (the "Trustee"), as Trustee, Paying Agent, Tender Agent and Bond Registrar, as the same will be amended and restated as of September 1, 2008.

Pursuant to a Loan Agreement by and between Kentucky Utilities Company (the "Company") and the Issuer, dated as of May 1, 2000 (the "Loan Agreement") (as the same has been amended and restated as of September 1, 2008 pursuant to an ordinance of the Issuer adopted October 14, 2008), proceeds from the sale of the Bonds, other than accrued interest, if any, paid by the initial purchasers thereof, were loaned by the Issuer to the Company. The Loan Agreement is a separate undertaking by and between the Company and the Issuer.

The Company will continue to repay the loan under the Loan Agreement by making payments to the Trustee in sufficient amounts to pay the principal of and interest and any premium on, and purchase price of, the Bonds. See "Summary of the Loan Agreement — General." Pursuant to the Indenture, the Issuer's rights under the Loan Agreement (other than with respect to certain indemnification and expense payments and notification rights) were assigned to the Trustee as security for the Bonds.

The proceeds of the Bonds were applied to the current refunding of the outstanding principal amount of the $12,900,000 "County of Mercer, Kentucky, Collateralized Solid Waste Disposal Facility Revenue Bonds (Kentucky Utilities Company Project), 1990 Series A," previously issued by the Issuer to finance certain solid waste disposal facilities (the "Project") owned by the Company.

The Company is an operating subsidiary of E.ON U.S. LLC (formerly known as LG&E Energy LLC) and E.ON AG (the "Parents"). See "Appendix A — Kentucky Utilities Company — Financial Statements and Additional Information." The Parents will have no obligation to make any payments due under the Loan Agreement or any other payments of principal, interest, premium or purchase price of the Bonds.

The Bonds are being reoffered at a Weekly Rate, but may be subsequently converted to bear interest at a Daily Rate, a Flexible Rate, a Semi-Annual Rate, an Annual Rate or a Dutch Auction Rate. **This Reoffering Circular pertains only to the Bonds during such period of time that they bear interest at the Weekly Rate.**

The Bonds are special and limited obligations of the Issuer, and the Issuer's obligation to pay the principal of and interest and any premium on, and purchase price of, the Bonds is limited solely to the revenues and other amounts received by the Trustee under the Indenture pursuant to the Loan Agreement and the Letter of Credit (as defined below). The Bonds will not constitute an indebtedness, general obligation or pledge of the faith and credit or taxing power of the Issuer, the Commonwealth of Kentucky or any political subdivision thereof. The Bonds are not entitled to the benefits of any financial guaranty insurance policies.

Concurrently with, and as a condition to, the reoffering of the Bonds, the Company will cause to be delivered an irrevocable transferable direct pay letter of credit (the "Letter of Credit"), issued by Commerzbank AG, New York Branch (the "Bank"), to provide for the timely payment of principal of and accrued interest (calculated for at least 45 days at the maximum rate of 10% per annum) on, and purchase price of, the Bonds. The Company will be required to reimburse the Bank for all amounts drawn by the Trustee under the Letter of Credit pursuant to the terms of a Reimbursement Agreement, to be dated as of December 17, 2008 (the "Reimbursement Agreement"), between the Company and the Bank. The Letter of Credit will expire on December 16, 2009, unless extended or earlier terminated.

Upon expiration of the Letter of Credit or any Alternate Credit Facility, the related Bonds will be subject to mandatory tender for purchase. See "Summary of the Bonds — Mandatory Purchases of Bonds — Mandatory Purchase upon Delivery, Cancellation, Substitution, Extension, Termination or Expiration of Any Credit Facility or Replacement with an Alternate Credit Facility." As used in this Reoffering Circular, "Bank" or "Credit Facility Issuer" refers to the Bank as the issuer of the Letter of Credit and any other issuer of any Alternate Credit Facility delivered in accordance with the Indenture; "Letter of Credit" or "Credit Facility" means the Letter of Credit delivered under the Indenture and, as applicable, any Alternate Credit Facility which may be subsequently delivered in accordance with the Indenture; and "Reimbursement Agreement" refers to the initial Reimbursement Agreement under which the Letter of Credit is provided and any subsequent agreement entered into between the Company and any other party in connection with the delivery of any Alternate Credit Facility.

Morgan Stanley & Co. Incorporated will be appointed under the Indenture to serve as Remarketing Agent for the Bonds. Any Remarketing Agent may resign or be removed and a successor Remarketing Agent may be appointed in accordance with the terms of the Indenture and the Remarketing Agreement for the Bonds between the Remarketing Agent and the Company.

Brief descriptions of the Company, the Issuer, the Bonds, the Loan Agreement, the Indenture, the Letter of Credit and the Reimbursement Agreement are included in this Reoffering Circular. Appendix A to this Reoffering Circular has been furnished by the Company. The Issuer and Bond Counsel assume no responsibility for the accuracy or completeness of such Appendix A or such information. Appendix B to this Reoffering Circular contains the opinion of Bond Counsel delivered on the date on which the Bonds were initially issued, and the proposed form of opinion of Bond Counsel to be delivered in connection with the reoffering of the Bonds and the delivery of the Letter of Credit. Appendix C to this Reoffering Circular contains information about the Bank. The Issuer and Bond Counsel assume no responsibility for the accuracy or completeness of such Appendix C or such information. Such descriptions and information do not purport to be complete, comprehensive or definitive and are not to be construed as a representation or a guaranty of accuracy or completeness. All references herein to the documents are qualified in their entirety by reference to such documents, and references herein to the Bonds are qualified in their entirety by reference to the definitive form thereof included in the Indenture. Copies of the Loan Agreement, the Indenture, the Letter of Credit and the Reimbursement Agreement will be available for inspection at the principal corporate trust office of the Trustee. Certain information relating to The Depository Trust Company ("DTC") and the book-entry-only system has been furnished by DTC. All statements herein are qualified in their entirety by reference to each such document and, with respect to the enforceability of certain rights and remedies, to laws and principles of equity relating to or affecting generally the enforcement of creditors' rights.

The Project

The Project has been completed and consists of certain solid waste disposal facilities of the Company used in connection with its Brown Generating Station situated in Mercer County.

The Issuer

The Issuer is a public body corporate and politic duly created and existing as a county and political subdivision under the Constitution and laws of the Commonwealth of Kentucky. The Issuer is authorized by Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (collectively, the "Act") to (a) reoffer the Bonds and (b) amend and restate and continue to perform its obligations under the Loan Agreement and the Indenture. The Issuer, through its legislative body, the Fiscal Court, has adopted one or more ordinances authorizing the issuance of the Bonds and the execution and delivery of the related documents.

THE BONDS ARE SPECIAL AND LIMITED OBLIGATIONS PAYABLE SOLELY AND ONLY FROM CERTAIN SOURCES, INCLUDING AMOUNTS TO BE RECEIVED BY THE TRUSTEE FROM THE LETTER OF CREDIT AND BY OR ON BEHALF OF THE ISSUER UNDER THE LOAN AGREEMENT. THE BONDS DO NOT CONSTITUTE AN INDEBTEDNESS, GENERAL OBLIGATION OR PLEDGE OF THE FAITH AND CREDIT OR TAXING POWER OF THE ISSUER, THE COMMONWEALTH OF KENTUCKY OR ANY POLITICAL SUBDIVISION THEREOF, AND DO NOT GIVE RISE TO A PECUNIARY LIABILITY OF THE ISSUER OR A CHARGE AGAINST ITS GENERAL CREDIT OR TAXING POWERS.

Summary of the Bonds

General

The Bonds will be issued in the aggregate principal amount set forth on the cover page of this Reoffering Circular and will mature on May 1, 2023. The Bonds are also subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption prior to maturity as described herein.

The Bonds currently bear interest at a Weekly Rate. From and after the Reoffering Date, the Bonds will bear interest at a Weekly Rate and will be payable on the first Business Day of each calendar month, commencing on January 2, 2009. The Bonds will continue to bear interest at the Weekly Rate until a Conversion to another Interest Rate Mode is specified by the Company or until the redemption or maturity of the Bonds. The permitted Interest Rate Modes for the Bonds are (i) the "Flexible Rate," (ii) the "Daily Rate," (iii) the "Weekly Rate," (iv) the "Semi-Annual Rate," (v) the "Annual Rate," (vi) the "Long Term Rate" and (vii) the "Dutch Auction Rate." Changes in the Interest Rate Mode will be effected, and notice of such changes will be given, as described below in "— Conversion of Interest Rate Modes and Changes of Long Term Rate Periods."

During each Rate Period for an Interest Rate Mode (other than a Dutch Auction Rate), the interest rate or rates for the Bonds in that Interest Rate Mode, and Flexible Rate Periods for Bonds accruing interest at a Flexible Rate, will be determined by the Remarketing Agent in accordance with the Indenture; provided that the interest rate or rates borne by any Bonds may not exceed the lesser of (i) the maximum interest rate permitted by applicable law or (ii) 10% per annum.

Interest on the Bonds which bear interest at a Flexible Rate, Daily Rate or Weekly Rate will be computed on the basis of a year of 365 or 366 days, as appropriate, and paid for the actual number of days elapsed. Interest on the Bonds which bear interest at a Semi-Annual Rate, Annual Rate or Long Term Rate will be computed on the basis of a 360-day year of twelve 30-day months. Interest on the Bonds which bear interest at a Dutch Auction Rate will be computed on the basis of a 360-day year for the actual number of days elapsed. Interest payable on any Interest Payment Date will be payable to the registered owner of the Bond as of the Record Date for such payment; provided that in the case of Bonds bearing interest at the Flexible Rate, interest will be payable to the registered owner of such Bond on the Interest Payment Date therefor. The Record Date, in the case of interest accrued at a Daily Rate or Weekly Rate, will be the close of business on the Business Day immediately preceding each Interest Payment Date, in the case of interest accrued at a Dutch Auction Rate, will be the close of business on the second Business Day immediately preceding each Interest Payment Date, and in the case of interest accrued at a Semi-Annual Rate, Annual Rate or Long Term Rate, will be the close of business on the fifteenth day (whether or not a Business Day) of the month preceding each Interest Payment Date.

The Bonds initially will be issued solely in book-entry-only form through DTC (or its nominee, Cede & Co.). So long as the Bonds are held in the book-entry-only system, DTC or its nominee will be the registered owner or holder of the Bonds for all purposes of the Indenture, the Bonds and this Reoffering Circular. See "— Book-Entry-Only System" below. Individual purchases of book-entry interests in the Bonds will be made in book-entry-only form in (i) denominations of $50,000 and integral multiples thereof, if bearing interest at the Dutch Auction Rate, (ii) denominations of $100,000 or any integral multiple thereof, if bearing interest at the Daily Rate, the Weekly Rate or the Semi-Annual Rate, (iii) denominations of $100,000 or any integral multiple of $5,000 in excess of $100,000, if bearing interest at Flexible Rates, or (iv) denominations of $5,000 and integral multiples thereof, if bearing interest at the Annual Rate or the Long Term Rate.

Except as otherwise described below for Bonds held in DTC's book-entry-only system, the principal or redemption price of the Bonds is payable at the designated corporate trust office in New York, New York, of the Trustee, as paying agent (the "Paying Agent"). Except as otherwise described below for Bonds held in DTC's book-entry-only system, interest on the Bonds is payable by check mailed to the owner of record; provided that interest payable on each Bond will be payable in immediately available funds by wire transfer within the continental United States or by deposit into a bank account maintained with the Paying Agent (i) if the Interest Rate Mode is the Daily Rate, the Weekly Rate, the Dutch Auction Rate or the Flexible Rate, or (ii) at the written request of any owner of record holding at least $1,000,000 aggregate principal amount of the Bonds, if the Interest Rate Mode is the Semi-Annual Rate, Annual Rate or Long Term Rate, received by the Trustee, as bond registrar (the "Bond Registrar"), at least one Business Day prior to any Record Date. Except as otherwise described below for Bonds held in DTC's book-entry-only system, if the Interest Rate Mode is the Flexible Rate, interest payable on each Bond will be paid only upon presentation and surrender of such Bond.

Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the principal office of the Bond Registrar, accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond (i) during the fifteen days before any mailing of a notice of redemption of Bonds, (ii) after such Bond has been called for redemption or (iii) for which a registered owner has submitted a demand for purchase (see "— Purchases of Bonds on Demand of Owner" below), or which has been purchased (see "— Payment of Purchase Price" below). Registration of transfers and exchanges will be made without charge to the registered owners of Bonds, except that the Bond Registrar may require any registered owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

The Bonds Are Not Insured

Upon the issuance of the Letter of Credit on the Reoffering Date, the Municipal Bond Insurance Policy (the "Bond Insurance Policy") issued by Ambac Assurance Corporation ("Ambac") on May 19, 2000 will have been irrevocably surrendered and cancelled. The Bonds described in this Reoffering Circular are not insured, and holders thereof will have no recourse to, under or against any bond insurance policy or bond insurer, including the aforementioned Bond Insurance Policy issued by Ambac.

Tender Agent

Owners may tender their Bonds, and in certain circumstances will be required to tender their Bonds, to the Tender Agent for purchase at the times and in the manner described herein under "— Summary of Certain Provisions of the Bonds," "— Purchases of Bonds on Demand of Owner," and "— Mandatory Purchases of Bonds." So long as the Bonds are held in DTC's book-entry-only system, the Trustee will act as Tender Agent under the Indenture. Any successor Tender Agent appointed pursuant to the Indenture will also be a Paying Agent.

Remarketing Agent

Morgan Stanley & Co. Incorporated will act as the Remarketing Agent with respect to the Bonds (the "Remarketing Agent"). The Remarketing Agent may resign or be removed and a successor Remarketing Agent may be appointed in accordance with the terms of the Indenture and the Remarketing Agreement for the Bonds between the Remarketing Agent and the Company.

Special Considerations Relating to the Remarketing Agent

The Remarketing Agent is paid by the Company.

The Remarketing Agent's responsibilities include determining the interest rate from time to time and remarketing Bonds that are optionally or mandatorily tendered by the owners thereof (subject, in each case, to the terms of the Remarketing Agreement), all as further described herein. The Remarketing Agent is appointed by the Issuer at the request of the Company and paid by the Company for its services. As a result, the interests of the Remarketing Agent may differ from those of existing holders and potential purchasers of Bonds.

The Remarketing Agent routinely purchases bonds for its own account.

The Remarketing Agent acts as remarketing agent for a variety of variable rate demand obligations and, in its sole discretion, routinely purchases such obligations for its own account in order to achieve a successful remarketing of the obligations (i.e., because there are otherwise not enough buyers to purchase the obligations) or for other reasons. The Remarketing Agent is permitted, but not obligated, to purchase tendered Bonds for its own account and, if it does so, it may cease doing so at any time without notice. The Remarketing Agent may also make a market in the Bonds by routinely purchasing and selling Bonds other than in connection with an optional or mandatory tender and remarketing. Such purchases and sales may be at or below par. However, the Remarketing Agent is not required to make a market in the Bonds. The Remarketing Agent may also sell any Bonds it has purchased to one or more affiliated investment vehicles for collective ownership or enter into derivative arrangements with affiliates or others in order to reduce its exposure to the Bonds. The purchase of Bonds by the Remarketing Agent may create the appearance that there is greater third party demand for the Bonds in the market than is actually the case. The practices described above also may result in fewer Bonds being tendered in a remarketing.

Bonds may be offered at different prices on any date.

As more fully described under the caption "— Determination of Interest Rates for Interest Rate Modes," the Remarketing Agent shall determine the minimum rate of interest per annum which in the opinion of the Remarketing Agent, would be necessary on and as of such day to remarket the Bonds in a secondary market transaction at a price equal to the principal amount thereof plus accrued interest thereon, if any, provided that such rate of interest shall not exceed 10% per annum. The interest rate will reflect, among other factors, the level of market demand for the Bonds (including whether the Remarketing Agent is willing to purchase Bonds for its own account). There may or may not be Bonds tendered and remarketed on a day that the rate on the Bonds are set, the Remarketing Agent may or may not be able to remarket any Bonds tendered for purchase on such date at par and the Remarketing Agent may sell Bonds at varying prices to different investors on such date or any other date. The Remarketing Agent is not obligated to advise purchasers in a remarketing if it does not have third party buyers for all of the Bonds at the remarketing price. In the event the Remarketing Agent owns any Bonds for its own account, it may, in its sole discretion in a secondary market transaction outside the tender process, offer such Bonds on any date, including the day that the rate on the Bonds are set, at a discount to par to some investors.

The ability to sell the Bonds other than through the tender process may be limited.

The Remarketing Agent may buy and sell Bonds other than through the tender process. However, it is not obligated to do so and may cease doing so at any time without notice and may require holders that wish to tender their Bonds to do so through the Trustee with appropriate notice. Thus, investors who purchase the Bonds, whether in a remarketing or otherwise, should not assume that they will be able to sell their Bonds other than by tendering the Bonds in accordance with the tender process.

Certain Definitions

As used herein, each of the following terms will have the meaning indicated. Certain capitalized terms used herein and not otherwise defined will have the meanings set forth in the Indenture.

"*Alternate Credit Facility*" means an irrevocable letter of credit, a municipal bond insurance policy, a surety bond, a line or lines of credit, a guarantee or other similar agreement or agreements or any other agreement or agreements used to provide liquidity or credit support for the Bonds, satisfactory to the Company and the Remarketing Agent and containing administrative provisions reasonably satisfactory to the Trustee, issued and delivered to the Trustee in accordance with the Indenture.

"*Annual Rate Period*" means the period beginning on, and including, the Conversion Date to the Annual Rate and ending on, and including, the day next preceding the second Interest Payment Date thereafter, and each successive twelve-month period (or portion thereof) thereafter until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Beneficial Owner*" means the person in whose name a Bond is recorded as such upon the systems of DTC and each DTC Participant (as defined herein) or the registered holder of such Bond if such Bond is not then registered in the name of Cede & Co.

"*Business Day*" means any day other than (i) a Saturday or Sunday or legal holiday or a day on which banking institutions located in the city in which the principal office of the Trustee, the Bond Registrar, the Tender Agent, the Paying Agent, the Company, the Credit Facility Issuer or the Remarketing Agent is located are authorized by law or executive order to close or (ii) a day on which the New York Stock Exchange is closed.

"*Conversion*" means any conversion from time to time in accordance with the terms of the Indenture of the Bonds from one Interest Rate Mode to another Interest Rate Mode.

"*Conversion Date*" means the date on which any Conversion becomes effective.

"*Credit Facility*" means an irrevocable direct pay letter of credit or other credit enhancement or liquidity support facility, or any combination thereof, delivered to and in favor of the Trustee for the benefit of the owners of the Bonds pursuant to the Indenture and designated as a "Credit Facility" under the Indenture, and includes the Initial Credit Facility or any Alternate Credit Facility delivered to the Trustee pursuant to the Indenture.

"*Credit Facility Issuer*" means the Initial Credit Facility Issuer and the issuer of any Credit Facility or Alternate Credit Facility subsequently in effect.

"*Daily Rate Period*" means the period beginning on, and including, the Conversion Date to the Daily Rate and ending on and including the day preceding the next Business Day and each period thereafter beginning on and including a Business Day and ending on and including the day preceding the next succeeding Business Day until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Dutch Auction Rate*" means the rate of interest to be borne by the Bonds during each Dutch Auction Rate Period determined in accordance with the Indenture.

"*Dutch Auction Rate Period*" means the period during which the Bonds bear interest at the Dutch Auction Rate.

"*Flexible Rate*" means the Interest Rate Mode for the Bonds in which the interest rate for each Bond is determined with respect to that Bond during each Flexible Rate Period applicable to that Bond, as provided in the Indenture.

"*Flexible Rate Period*" means with respect to any Bond, each period (which may be from one day to 270 days, or such lower maximum number of days as is then permitted under the Indenture) determined for such Bond, as provided in the Indenture.

"*Initial Credit Facility*" means the irrevocable direct pay letter of credit issued by the Initial Credit Facility Issuer to the Trustee with respect to the Bonds on the Reoffering Date.

"*Initial Credit Facility Issuer*" means Commerzbank AG, New York Branch.

"*Interest Payment Date*" means (i) if the Interest Rate Mode is the Daily Rate or the Weekly Rate, the first Business Day of each calendar month, (ii) if the Interest Rate Mode is the Flexible Rate, for each Bond the first Business Day following the last day of each Flexible Rate Period for such Bond, (iii) if the Interest Rate Mode is the Semi-Annual Rate, the Annual Rate or the Long Term Rate, May 1 and November 1; (iv) if the Interest Rate Mode is the Dutch Auction Rate Mode, the dates determined in accordance with the terms of the Indenture; and (v) any Conversion Date (including the date of a failed Conversion) or the effective date of a change to a new Long Term Rate Period for such Bonds. In any case, the final Interest Payment Date will be the maturity date of the Bonds.

"*Interest Period*" means for all Bonds (or for any Bond if the Interest Rate Mode is the Flexible Rate) the period from and including each Interest Payment Date to and including the day immediately preceding the next Interest Payment Date, provided, however that the first Interest Period for the Bonds will begin on (and include) the date of issuance of the Bonds and the final Interest Period will end on April 30, 2023.

"*Interest Rate Mode*" means the Dutch Auction Rate, the Flexible Rate, the Daily Rate, the Weekly Rate, the Semi-Annual Rate, the Annual Rate and the Long Term Rate.

"*Long Term Rate Period*" means any period established by the Company as hereinafter set forth under "— Determination of Interest Rates for Interest Rate Modes — Long Term Rates and Long Term Rate Periods" and beginning on, and including, the Conversion Date to the Long Term Rate and ending on, and including, the day preceding the last Interest Payment Date for such period and, thereafter, each successive period of the same duration as the Long Term Rate Period previously established until the day preceding the earliest of the change to a different Long Term Rate Period, the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Prevailing Market Conditions*" means, without limitation, the following factors: existing short-term or long-term market rates for securities, the interest on which is excluded from gross income for federal income tax purposes; indexes of such short-term or long-term rates and the existing market supply and demand for securities bearing such short-term or long-term rates; existing yield curves for short-term or long-term securities for obligations of credit quality comparable to the Bonds, the interest on which is excluded from gross income for federal income tax purposes; general economic conditions; industry economic and financial conditions that may affect or be relevant to the Bonds; and such other facts, circumstances and conditions as the Remarketing Agent, in its sole discretion, determines to be relevant.

"*Purchase Date*" means any date on which Bonds are to be purchased on the demand of the registered owners thereof or are subject to mandatory purchase as described in the Indenture.

"*Reimbursement Agreement*" means the Reimbursement Agreement, to be dated as of December 17, 2008, between the Company and the Initial Credit Facility Issuer, as the same may be amended from time to time, and any other agreement between the Company and a Credit Facility Issuer, setting forth the obligations of the Company to such Credit Facility Issuer arising out of any payments under such Credit Facility and which provides that it will be deemed to be a Reimbursement Agreement for the purpose of the Indenture.

"*Semi-Annual Rate Period*" means the period beginning on, and including, the Conversion Date to the Semi-Annual Rate, and ending on, and including, the day preceding the first Interest Payment Date thereafter and each successive six-month period thereafter beginning on and including an Interest Payment Date and ending on and including the day next preceding the next Interest Payment Date until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Weekly Rate Period*" means the period beginning on, and including, the Conversion Date to the Weekly Rate, and ending on, and including, the next Tuesday, and thereafter the period beginning on, and including, each Wednesday and ending on, and including, the earliest of the next Tuesday, the day preceding the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

Summary of Certain Provisions of the Bonds

The following table summarizes, for each of the permitted Interest Rate Modes (except the Dutch Auction Rate): the dates on which interest will be paid (*Interest Payment Dates*); the dates on which each interest rate will be determined (*Interest Rate Determination Dates*); the period of time (*Interest Rate Periods*) each interest rate will be in effect (provided that the initial Interest Rate Period for each Interest Rate Mode may begin on a different date from that specified, which date will be the Conversion Date or the date of a change in the Long Term Rate, as applicable); the dates on which registered owners may tender their Bonds for purchase to the Tender Agent and the notice requirements therefor (provided that while the Bonds are held in book-entry-only form, all notices of tender for purchase will be given by Beneficial Owners in the manner described under "— Purchases of Bonds on Demand of Owner — Notice Required for Purchases") (*Purchase on Demand of Owner; Required Notice*); the dates on which the Bonds are subject to mandatory tender for purchase (*Mandatory Purchase Dates*); the redemption provisions applicable to the Bonds (*Redemption*); the notice requirements for redemption and mandatory tender for purchase (*Notices of Redemption and Mandatory Purchases*); and the manner by which registered owners will receive payments of principal, interest, redemption price and purchase price (*Manner of Payment*). All times stated are New York City time.

	FLEXIBLE RATE	DAILY RATE	WEEKLY RATE
Interest Payment Dates	With respect to any Bond, the first Business Day following the last day of each Flexible Rate Period for that Bond.	The first Business Day of each calendar month.	The first Business Day of each calendar month.
Interest Rate Determination Dates	For each Bond, not later than 1:00 p.m. on the first day of each Flexible Rate Period for such Bond.	Not later than 9:30 a.m. on each Business Day.	Not later than 10:00 a.m. on the first day of each Weekly Rate Period or, if not a Business Day, on the next succeeding Business Day.
Interest Rate Periods	For each Bond, each Flexible Rate Period will be of a duration designated by the Remarketing Agent of one day to 270 days (or lower maximum number as specified in the Indenture); must end on a day immediately prior to a Business Day.	From and including each Business Day to but not including the next Business Day.	From and including each Wednesday to and including the following Tuesday.
Purchase on Demand of Owner; Required Notice*	No purchase on demand of the owner.	Any Business Day; by written or telephonic notice, promptly confirmed in writing, to the Tender Agent by 10:00 a.m. on such Business Day.	Any Business Day; by written notice to the Tender Agent not later than 5:00 p.m. on a Business Day at least seven days prior to the Purchase Date.
Mandatory Purchase Dates	Any Conversion Date; with respect to each Bond, on each Interest Payment Date for such Bond; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.
Redemption	Optional at par on any Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day (other than extraordinary optional redemption as a result of damage, destruction or condemnation which will be on an Interest Payment Date).	Optional, Extraordinary Optional and Mandatory at par on any Business Day.	Optional, Extraordinary Optional and Mandatory at par on any Business Day.
Notices of Conversion, Redemption and Mandatory Purchases*	Not fewer than 15 days (30 days notice of Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 60 days for notice of Conversion or redemption. No notice of mandatory purchase following end of each Flexible Rate Period.	Not fewer than 15 days (30 days notice of Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 60 days for notice of Conversion or redemption. Not fewer than 15 days or greater than 45 days for notice of mandatory purchase.	Not fewer than 15 days (30 days notice of Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 60 days for notice of Conversion or redemption. Not fewer than 15 days or greater than 45 days for notice of mandatory purchase.
Manner of Payment*	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.

* So long as DTC or its nominee is the registered owner of the Bonds, notices of redemption and mandatory purchases shall be sent to Cede & Co., payments of principal, redemption and purchase price of and interest on the Bonds will be paid through the facilities of DTC and notices of mandatory purchase may be given not less than five days prior to the Purchase Date. See "— Book-Entry-Only System" below.

	SEMI-ANNUAL	**ANNUAL**	**LONG TERM**
Interest Payment Date	Each May 1 and November 1.	Each May 1 and November 1.	Each May 1 and November 1; any Conversion Date; and the effective date of any change to a new Long Term Rate Period.
Interest Rate Determination Dates	Not later than 12:00 noon on the Business Day preceding the first day of the Semi-Annual Rate Period.	Not later than 12:00 noon on the Business Day preceding the first day of the Annual Rate Period.	Not later than 12:00 noon on the Business Day preceding the first day of the Long Term Rate Period.
Interest Rate Periods	Each six-month period from and including each May 1 and November 1 to and including the day preceding the next Interest Payment Date.	Each one-year period from and including each May 1 and November 1 to and including the day immediately preceding the second Interest Payment Date thereafter.	Each period designated by the Company of more than one year in duration and which is an integral multiple of six months, from and including the first day of such period (May 1 and November 1) to and including the day immediately preceding the last Interest Payment Date for that period.
Purchase on Demand of Owner; Required Notice*	On any Interest Payment Date; by written notice to the Tender Agent on any Business Day not later than the fifteenth day prior to the Purchase Date.	On the final Interest Payment Date for the Annual Rate Period; by written notice to the Tender Agent on any Business Day not later than the fifteenth day prior to the Purchase Date.	On the final Interest Payment Date for the Long Term Rate Period; by written notice to the Tender Agent on a Business Day not later than the fifteenth day prior to the Purchase Date.
Mandatory Purchase Dates	Any Conversion Date; the first Business Day after the end of each Semi-Annual Rate Period; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; the first Business Day after the end of each Annual Rate Period; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; the first Business Day after the end of each Long Term Rate Period; the effective date of a change of Long Term Rate Period; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.
Redemption	Optional at par on any Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day (other than extraordinary optional redemption as a result of damage, destruction or condemnation which will be on an Interest Payment Date).	Optional at par on the final Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day.	Optional at times and prices dependent on the length of the Long Term Rate Period; Extraordinary Optional and Mandatory at par, on any Business Day.
Notices of Conversion, Redemption and Mandatory Purchases*	Not fewer than 30 days or greater than 60 days for notice of Conversion or redemption. Not fewer than 15 days or greater than 45 days for notice of mandatory purchase.	Not fewer than 30 days or greater than 60 days for notice of Conversion or redemption. Not fewer than 15 days or greater than 45 days for notice of mandatory purchase.	Not fewer than 30 days or greater than 60 days for notice of Conversion or redemption. Not fewer than 15 days or greater than 45 days for notice of mandatory purchase.
Manner of Payment*	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner, of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner, of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner, of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.

* So long as DTC or its nominee is the registered owner of the Bonds, notices of redemption and mandatory purchases shall be sent to Cede & Co., payments of principal, redemption and purchase price of and interest on the Bonds will be paid through the facilities of DTC and notices of mandatory purchase may be given not less than five days prior to the Purchase Date. See "— Book-Entry-Only System" below.

Determination of Interest Rates for Interest Rate Modes

Daily Rate. If the Interest Rate Mode for the Bonds is the Daily Rate, the interest rate on the Bonds for any Business Day will be the rate established by the Remarketing Agent no later than 9:30 a.m. (New York City time) on such Business Day as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such Business Day at a price equal to the principal amount thereof, plus accrued interest, if any, thereon. For any day which is not a Business Day or if the Remarketing Agent does not give notice of a change in the interest rate, the interest rate on the Bonds will be the interest rate in effect for the immediately preceding Business Day.

Weekly Rate. If the Interest Rate Mode for the Bonds is the Weekly Rate, the interest rate on the Bonds for a particular Weekly Rate Period will be the rate established by the Remarketing Agent no later than 10:00 a.m. (New York City time) on the first day of such Weekly Rate Period or, if such first day is not a Business Day, on the next succeeding Business Day, as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof, plus accrued interest, if any, thereon.

Flexible Rates and Flexible Rate Periods. If the Interest Rate Mode for the Bonds is the Flexible Rate, the interest rate on a Bond for a specific Flexible Rate Period will be the rate established by the Remarketing Agent no later than 1:00 p.m. (New York City time) on the first day of that Flexible Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell such Bond on that day at a price equal to the principal amount thereof. Each Flexible Rate Period applicable for a Bond will be determined separately by the Remarketing Agent on or prior to the first day of such Flexible Rate Period as being the Flexible Rate Period permitted under the Indenture which, in the judgment of the Remarketing Agent, taking into account then Prevailing Market Conditions, will, with respect to such Bond, ultimately produce the lowest overall interest cost on the Bonds while the Interest Rate Mode for the Bonds is the Flexible Rate. Each Flexible Rate Period will be from one day to 270 days in length and will end on a day preceding a Business Day. If the Remarketing Agent fails to set the length of a Flexible Rate Period for any Bond, a new Flexible Rate Period lasting to, but not including, the next Business Day (or until the earlier Conversion or maturity of the Bonds) will be established automatically in accordance with the Indenture.

Semi-Annual Rate. If the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the interest rate on the Bonds for a particular Semi-Annual Rate Period will be the rate established by the Remarketing Agent no later than 12:00 noon (New York City time) on the Business Day immediately preceding the first day of such Semi-Annual Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof.

Annual Rate. If the Interest Rate Mode for the Bonds is the Annual Rate, the interest rate on the Bonds for a particular Annual Rate Period will be the rate of interest established by the Remarketing Agent no later than 12:00 noon (New York City time) on the Business Day preceding the first day of such Annual Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof.

Auction Rate. If the Interest Rate Mode for the Bonds is the Dutch Auction Rate, the interest rate on the Bonds for a particular Dutch Auction Rate Period will be the rate established in accordance with the procedures set forth in the Indenture.

Long Term Rates and Long Term Rate Periods. If the Interest Rate Mode for the Bonds is the Long Term Rate, the interest rate on the Bonds for a particular Long Term Rate Period will be the rate established by the Remarketing Agent no later than 12:00 noon (New York City time) on the Business Day preceding the first day of such Long Term Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof. The Company will establish the duration of the Long Term Rate Period at the time that it directs the Conversion of the Interest Rate Mode to the Long Term Rate, and thereafter each successive Long Term Rate Period will be the same as the Long Term Rate Period so established by the Company until a different Long Term Rate Period is specified by the Company in accordance with the Indenture (in which case the duration of that Long Term Rate Period will control succeeding Long Term Rate Periods), subject in all cases to the occurrence of a Conversion Date or the maturity of the Bonds. Each Long Term Rate Period will be more than one year in duration, will be for a period which is an integral multiple of six months and will end on the day next preceding an Interest Payment Date; provided that if a Long Term Rate Period commences on a date other than a May 1 or November 1, such Long Term Rate Period may be for a period which is not an integral multiple of six months but will be of a duration as close as possible to (but not in excess of) such Long Term Rate Period established by the Company and will terminate on a day preceding an Interest Payment Date, and each successive Long Term Rate Period thereafter will be for the full period established by the Company until a different Long Term Rate Period is specified by the Company in accordance with the Indenture or until the occurrence of a Conversion Date or the maturity of the Bonds; provided further that no Long Term Rate Period will extend beyond the final maturity date of the Bonds.

Failure to Determine Rate. If for any reason the interest rate for a Bond is not determined by the Remarketing Agent, except as described below under "— Conversion of Interest Rate Modes and Changes of Long Term Rate Periods — Change of Long Term Rate Period" and "— Cancellation of Conversion of Interest Rate Mode," the interest rate for such Bond for the next succeeding interest rate period will be the interest rate in effect for such Bond for the preceding interest rate period and, pursuant to the terms of the Indenture, there will be no change in the then applicable Long Term Rate Period or any Conversion from the then applicable Interest Rate Mode. Notwithstanding the foregoing, if for any reason the interest rate for a Bond bearing interest at a Flexible Rate is not determined by the Remarketing Agent, the interest rate for such Bond for the next succeeding Interest Period will be equal to The Bond

Market Association Municipal Swap Index™ (the "Municipal Index") as defined in the Indenture and the Interest Period for such Bond will extend through the day preceding the next Business Day, until the Trustee is notified of a new Flexible Rate and Flexible Rate Period determined for such Bond by the Remarketing Agent.

Conversion of Interest Rate Modes and Changes of Long Term Rate Periods

Method of Conversion. The Interest Rate Mode for the Bonds is subject to Conversion from time to time, in whole but not in part, on the dates specified below under "— Limitations on Conversion," at the option of the Company, upon notice from the Bond Registrar to the registered owners of the Bonds, as described below. With any notice of Conversion, the Company must also deliver to the Bond Registrar and the Credit Facility Issuer an opinion of Bond Counsel stating that such Conversion is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes.

Conditions Precedent to Conversions. The following conditions are applicable to Conversions of the Bonds:

(a) any Credit Facility to be held by the Trustee after the Conversion Date must be sufficient to cover the principal of and accrued interest on the outstanding Bonds for the maximum Interest Period permitted for that particular Interest Rate Mode plus 10 days at the maximum interest rate, and if a Credit Facility is to be held by the Trustee after the Conversion of the Bonds to a Long Term Rate Period, that Credit Facility must also extend for the entire Long Term Rate Period plus 10 days at the maximum interest rate; and

(b) if a Credit Facility is then in effect and the purchase price of the Bonds under the Indenture includes any premium, the Trustee will be entitled to draw on that Credit Facility in an aggregate amount sufficient to pay the applicable purchase price (including such premium) or, in the alternative, available moneys will be available in the necessary amount and are applied to the payment of such premium.

Limitations on Conversion. Any Conversion of the Interest Rate Mode for the Bonds must be in compliance with the following conditions: (i) the Conversion Date must be a date on which the Bonds are subject to optional redemption (see "— Redemptions — Optional Redemption" below); provided that any Conversion from the Daily Rate Period to a Weekly Rate Period or from the Weekly Rate Period to the Daily Rate Period must be on a Wednesday and, if the Conversion is to or from a Dutch Auction Rate Period, the Conversion Date must be the last Interest Payment Date in respect of that Dutch Auction Rate Period; (ii) if the proposed Conversion Date would not be an Interest Payment Date but for the Conversion, the Conversion Date must be a Business Day; (iii) if the Conversion is from the Flexible Rate, (a) the Conversion Date may be no earlier than the latest Interest Payment Date established prior to the giving of notice to the Remarketing Agent of such proposed Conversion and (b) no further Interest Payment Date may be established while the Interest Rate Mode is then the Flexible Rate if such Interest Payment Date would occur after the effective date of that Conversion; and (iv) after a determination is made requiring mandatory redemption of all Bonds pursuant to the

Indenture (see "— Redemptions" below), no change in the Interest Rate Mode may be made prior to such mandatory redemption.

Change of Long Term Rate Period. The Company may change from one Long Term Rate Period to another Long Term Rate Period on any Business Day on which the Bonds are subject to optional redemption as described under "— Redemptions — Optional Redemption" below upon notice from the Bond Registrar to the owners of Bonds as described below. With any notice of such change, the Company must also deliver an opinion of Bond Counsel stating that such change is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. Notwithstanding the foregoing, the Long Term Rate Period will not be changed to a new Long Term Rate Period if (A) the Remarketing Agent has not determined the interest rate for the new Long Term Rate Period in accordance with the terms of the Indenture or (B) the Bond Registrar receives written notice from Bond Counsel prior to the effective date of the change to the effect that the opinion of such Bond Counsel required under the Indenture has been rescinded. Upon the occurrence of any of the events described in the preceding sentence, the Bonds will bear interest at the Weekly Rate commencing on the date which would have been the effective date of the proposed change of Long Term Rate Period, subject to the provisions described below under "— Cancellation of Conversion of Interest Rate Mode."

Notice to Owners of Conversion of Interest Rate Mode or of Change of Long Term Rate Period. The Bond Registrar will notify each registered owner of the Conversion or change of Long Term Rate Period, as applicable, by first class mail at least 15 days (30 days in the case of Conversion from or to the Semi-Annual Rate, the Annual Rate or a Long Term Rate or in the case of a change in the Long Term Rate Period) but not more than 60 days before each Conversion Date or each effective date of a change in the Long Term Rate Period. The notice will state those matters required to be set forth therein under the Indenture.

Cancellation of Conversion of Interest Rate Mode. Notwithstanding the foregoing, no Conversion will occur if (A) the Remarketing Agent has not determined the initial interest rate for the new Interest Rate Mode in accordance with the terms of the Indenture, (B) the Bonds that are to be purchased are not remarketed or sold by the Remarketing Agent or (C) the Bond Registrar receives written notice from Bond Counsel prior to the opening of business on the effective date of Conversion to the effect that the opinion of such Bond Counsel required under the Indenture has been rescinded. If such Conversion fails to occur, such Bonds in the Dutch Auction Rate will remain in such Interest Rate Mode and Bonds in any other Interest Rate Mode will automatically be converted to the Weekly Rate (with the first period adjusted in length so that the last day of such period will be a Tuesday) at the rate determined by the Remarketing Agent on the failed Conversion Date; provided, that there must be delivered to the Issuer, the Trustee, the Tender Agent, the Company, the Credit Facility Issuer and the Remarketing Agent an opinion of Bond Counsel to the effect that determining the interest rate to be borne by the Bonds at a Weekly Rate is authorized or permitted by the Act and is authorized under the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. If such opinion is not delivered on the failed Conversion Date, the Bonds will bear interest for a Rate Period of the same type and of substantially the same length as the Rate Period in effect prior to the failed Conversion Date at a rate of interest determined by the Remarketing Agent on the failed Conversion Date (or if shorter, the Rate

Period ending on the date before the maturity date); provided that if the Bonds then bear interest at the Long Term Rate, and if such opinion is not delivered on the date which would have been the effective date of a new Long Term Rate Period, the Bonds will bear interest at the Annual Rate, commencing on such date, at an Annual Rate determined by the Remarketing Agent on such date. If the proposed Conversion of Bonds fails as described herein, any mandatory purchase of such Bonds will remain effective.

Purchases of Bonds on Demand of Owner

If the Bonds are in the book-entry-only system, demands for purchase may be made by Beneficial Owners only through such Beneficial Owner's Direct Participant (as defined under the caption "— Book-Entry-Only System"). If the Bonds are in certificated form, demands for purchase may be made only by registered owners. When the Interest Rate Mode is the Dutch Auction Rate, the Bonds are not subject to purchase on demand of the owners thereof.

Daily Rate. If the Interest Rate Mode for the Bonds is the Daily Rate, any Bond will be purchased on the demand of the registered owner thereof on any Business Day during a Daily Rate Period at a purchase price equal to the principal amount thereof plus accrued interest, if any, to the Purchase Date upon written notice or telephonic notice to the Tender Agent at its principal office not later than 10:00 a.m. (New York City time) on such Business Day.

Weekly Rate. If the Interest Rate Mode for the Bonds is the Weekly Rate, any Bond will be purchased on the demand of the registered owner thereof on any Business Day during a Weekly Rate Period at a purchase price equal to the principal amount thereof plus accrued interest, if any, to the Purchase Date upon written notice to the Tender Agent at its principal office at or before 5:00 p.m. (New York City time) on a Business Day not later than the seventh day prior to the Purchase Date.

Semi-Annual Rate. If the Interest Rate Mode for the Bonds is the Semi-Annual Rate, any Bond will be purchased on the demand of the registered owner thereof on any Interest Payment Date for a Semi-Annual Rate Period at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Annual Rate. If the Interest Rate Mode for the Bonds is the Annual Rate, any Bond will be purchased on the demand of the registered owner thereof on the final Interest Payment Date for such Annual Rate Period at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Long Term Rate. If the Interest Rate Mode for the Bonds is the Long Term Rate, any Bond will be purchased on the demand of the registered owner thereof on the final Interest Payment Date for such Long Term Rate Period (unless such date is the final maturity date) at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Limitations on Purchases on Demand of Owner. Notwithstanding the foregoing, there will be no purchase of (a) a portion of any Bond unless the portion to be purchased and the portion to be retained each will be in an authorized denomination or (b) any Bond upon the demand of the registered owner if an Event of Default under the Indenture with respect to the payment of principal of, interest on, or purchase price of, the Bonds has occurred and is continuing. Also, if the Interest Rate Mode for the Bonds is the Flexible Rate, the Bonds will not be subject to purchase on the demand of the registered owners thereof, but each Bond will be subject to mandatory purchase on each Conversion Date and on the Interest Payment Date with respect to such Bond, as described below under the caption "— Mandatory Purchases of Bonds."

Notice Required for Purchases. Any written notice delivered to the Tender Agent by an owner demanding the purchase of Bonds must (A) be delivered by the time and dates specified above, (B) state the number and principal amount (or portion thereof) of such Bond to be purchased, (C) state the Purchase Date on which such Bond is to be purchased, (D) irrevocably request such purchase and state that the owner agrees to deliver such Bond, duly endorsed in blank for transfer, with all signatures guaranteed, to the Tender Agent at or prior to 11:00 a.m. (1:00 p.m. if a tender during a Daily Rate Period and 12:00 noon if a tender during a Weekly Rate Period) (New York City time) on such Purchase Date.

Mandatory Purchases of Bonds

Mandatory Purchase on Conversion Dates or Change by the Company in Long Term Rate Period. The Bonds will be subject to mandatory purchase at a purchase price equal to the principal amount thereof, plus accrued interest, if any, to the Purchase Date, plus, if the Interest Rate Mode is the Long Term Rate, the redemption premium, if any, which would be payable as described under "— Redemptions — Optional Redemption" below, if the Bonds were redeemed on the Purchase Date (A) on each Conversion Date and (B) on the effective date of any change by the Company of the Long Term Rate Period. Such tender and purchase will be required even if the change in Long Term Rate Period or the Conversion is canceled pursuant to the Indenture.

Mandatory Purchase on Each Interest Payment Date for Flexible Rate Period. Whenever the Interest Rate Mode for the Bonds is the Flexible Rate, each Bond will be subject to mandatory purchase at a purchase price equal to the principal amount thereof, without premium, plus accrued interest, if any, to the Purchase Date, on each Interest Payment Date that interest on such Bond is payable at an interest rate determined for the Flexible Rate. Owners of Bonds will receive no notice of such mandatory purchase.

Mandatory Purchase on Day after End of the Semi-Annual Rate Period, the Annual Rate Period or the Long Term Rate Period. Whenever the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the Annual Rate or the Long Term Rate, such Bonds will be subject to mandatory purchase on the Business Day following the end of each Semi-Annual Rate Period, Annual Rate Period or Long Term Rate Period, as the case may be, for such Bond at a purchase price equal to the principal amount thereof plus accrued interest, if any, to such date.

Mandatory Purchase upon Delivery, Cancellation, Substitution, Extension, Termination or Expiration of Any Credit Facility or Replacement with an Alternate Credit Facility. If, at the option of the Company, a Credit Facility (other than the initial Letter of Credit) is delivered with respect to the Bonds subsequent to the Reoffering Date, the Bonds will be subject to mandatory tender for purchase at a purchase price equal to 100% of the principal amount thereof, plus accrued interest, if any, to the Purchase Date on the date of the delivery of the Credit Facility. In addition, if the Bonds are secured by a Credit Facility, the Bonds will be subject to mandatory tender for purchase at a purchase price equal to 100% of the principal amount thereof, plus accrued interest, if any, (A) on the Interest Payment Date at least five days prior to the date of the cancellation of or the expiration of the term of the then current Credit Facility and (B) on the Interest Payment Date on which a Credit Facility is replaced with an Alternate Credit Facility.

Notice to Owners of Mandatory Purchases. Notice to owners of a mandatory purchase of Bonds (except for mandatory purchase on each Interest Payment Date for Flexible Rate Periods) will be given by the Bond Registrar, by first class mail at least 15 days but not more than 45 days before the Purchase Date; provided, however, as an alternative to the foregoing, if DTC or its nominee is the registered owner of the Bonds, notice may be given to DTC not less than five days before the Purchase Date. The notice of mandatory purchase will state those matters required to be set forth therein under the Indenture. No notice of mandatory purchase will be given in connection with a mandatory purchase on an Interest Payment Date for a Flexible Rate Period.

Remarketing and Purchase of Bonds

The Indenture provides that, subject to the terms of a Remarketing Agreement with the Company, the Remarketing Agent will use its reasonable best efforts to offer for sale Bonds purchased upon demand of the owners thereof and, unless otherwise instructed by the Company and with the consent of any Credit Facility Issuer, upon mandatory purchase, provided that Bonds will not be remarketed upon the occurrence and continuance of certain Events of Default under the Indenture, except in the sole discretion of the Remarketing Agent. Each such sale will be at a price equal to the principal amount thereof, plus interest accrued to the date of sale. The Remarketing Agent, the Trustee, the Paying Agent, the Bond Registrar or the Tender Agent each may purchase any Bonds offered for sale for its own account.

On each date Bonds are to be purchased pursuant to optional or mandatory purchase under the Indenture, such Bonds will be purchased from the following sources in the order of priority indicated, provided that funds derived from clause (c) may not be combined with the funds derived from clauses (a) or (b) to purchase any Bonds:

(a) proceeds of the remarketing of such Bonds to persons other than the Company, its affiliates or the Issuer and furnished to the Tender Agent by the Remarketing Agent and deposited directly into, and held in, the Remarketing Proceeds Subaccount of the Purchase Fund established with the Tender Agent under the Indenture;

(b) proceeds of the Credit Facility, if any, furnished by the Trustee, as Tender Agent, and deposited by the Tender Agent directly into, and held in, the Credit Facility Subaccount of the Purchase Fund; and

(c) moneys paid by the Company (including the proceeds of the remarketing of the Bonds to the Company, its affiliates or the Issuer) to pay the purchase price to the Tender Agent.

If there is no Credit Facility in operation to secure the Bonds, any Bonds will be purchased with any moneys made available by the Company, including proceeds from the remarketing of the Bonds.

Payment of Purchase Price

When a book-entry-only system is not in effect, payment of the purchase price of any Bond will be payable (and delivery of a replacement Bond in exchange for the portion of any Bond not purchased if such Bond is purchased in part will be made) on the Purchase Date upon delivery of such Bond to the Tender Agent on such Purchase Date; provided that such Bond must be delivered to the Tender Agent: (i) at or prior to 12:00 noon (New York City time), in the case of Bonds delivered for purchase during a Weekly Rate Period or Flexible Rate Period, (ii) at or prior to 1:00 p.m. (New York City time), in the case of Bonds delivered for purchase during a Daily Rate Period or (iii) at or prior to 11:00 a.m. (New York City time), in the case of Bonds delivered for purchase during a Semi-Annual Rate Period, Annual Rate Period or Long Term Rate Period. If the date of such purchase is not a Business Day, the purchase price will be payable on the next succeeding Business Day.

Any Bond delivered for payment of the purchase price must be accompanied by an instrument of transfer thereof in form satisfactory to the Tender Agent executed in blank by the registered owner thereof and with all signatures guaranteed. The Tender Agent may refuse to accept delivery of any Bond for which an instrument of transfer satisfactory to it has not been provided and has no obligation to pay the purchase price of such Bond until a satisfactory instrument is delivered.

If the registered owner of any Bond (or portion thereof) that is subject to purchase pursuant to the Indenture fails to deliver such Bond with an appropriate instrument of transfer to the Tender Agent for purchase on the Purchase Date, and if the Tender Agent is in receipt of the purchase price therefor, such Bond (or portion thereof) nevertheless will be deemed purchased on the Purchase Date thereof. Any owner who so fails to deliver such Bond for purchase on (or before) the Purchase Date will have no further rights thereunder, except the right to receive the purchase price thereof from those moneys deposited with the Tender Agent in the Purchase Fund pursuant to the Indenture upon presentation and surrender of such Bond to the Tender Agent properly endorsed for transfer in blank with all signatures guaranteed.

When a book-entry-only system is in effect, the requirement for physical delivery of the Bonds will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on the records of DTC to the participant account of the Tender Agent.

Redemptions

Optional Redemption.

(a) Whenever the Interest Rate Mode for the Bonds is the Daily Rate or the Weekly Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof, plus interest accrued, if any, to the redemption date, on any Business Day.

(b) Whenever the Interest Rate Mode for a Bond is the Flexible Rate, such Bond will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof on any Interest Payment Date for that Bond.

(c) Whenever the Interest Rate Mode for the Bonds is the Dutch Auction Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, on the Business Day immediately succeeding any auction date, at a redemption price of 100% of the principal amount thereof, together with accrued interest to the redemption date.

(d) Whenever the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof on any Interest Payment Date.

(e) Whenever the Interest Rate Mode for the Bonds is the Annual Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof on the final Interest Payment Date for each Annual Rate Period.

(f) Whenever the Interest Rate Mode for the Bonds is the Long Term Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, (1) on the final Interest Payment Date for the then-current Long Term Rate Period at a redemption price of 100% of the principal amount thereof and (2) prior to the end of the then-current Long Term Rate Period at any time during the redemption periods and at the redemption prices set forth below, plus in each case interest accrued, if any, to the redemption date:

Original Length of Current Long Term Rate Period (Years)	Commencement of Redemption Period	Redemption Price as Percentage of Principal
More than or equal to 11 years	First Interest Payment Date on or after the tenth anniversary of commencement of Long Term Rate Period	101%, declining 1% on the next succeeding anniversary of the first day of the redemption period, and thereafter 100%
Less than 11 years	Non-callable	Non-callable

Subject to certain conditions, including provision of an opinion of Bond Counsel that a change in the redemption provisions of the Bonds will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, the redemption periods and redemption prices may be revised, effective as of the Conversion Date, the date of a change in the Long Term Rate Period or a Purchase Date on the final Interest Payment Date during a Long Term Rate Period, to reflect Prevailing Market Conditions on such date as determined by the Remarketing Agent in its judgment.

Extraordinary Optional Redemption in Whole. The Bonds may be redeemed by the Issuer in whole at any time at 100% of the principal amount thereof plus accrued interest to the redemption date upon the exercise by the Company of an option under the Loan Agreement to prepay the loan if any of the following events shall have occurred within 180 days preceding the giving of written notice by the Company to the Trustee of such election:

(i) if in the judgment of the Company, unreasonable burdens or excessive liabilities have been imposed upon the Company after the issuance of the Bonds with respect to the Project or the operation thereof, including without limitation federal, state or other ad valorem property, income or other taxes not imposed on the date of the Bonds were issued, other than ad valorem taxes levied upon privately owned property used for the same general purpose as the Project;

(ii) if the Project or a portion thereof or other property of the Company in connection with which the Project is used has been damaged or destroyed to such an extent so as, in the judgment of the Company, to render the Project or such other property of the Company in connection with which the Project is used unsatisfactory to the Company for its intended use, and such condition continues for a period of six months;

(iii) there has occurred condemnation of all or substantially all of the Project or the taking by eminent domain of such use or control of the Project or other property of the Company in connection with which the Project is used so as, in the judgment of the Company, to render the Project or such other property of the Company unsatisfactory to the Company for its intended use;

(iv) in the event changes, which the Company cannot reasonably control, in the economic availability of materials, supplies, labor, equipment or other properties or things necessary for the efficient operation of the generating station where the Project is located have occurred, which, in the judgment of the Company, render the continued operation of such generating station or any generating unit at such station uneconomical; or changes in circumstances after the issuance of the Bonds, including but not limited to changes in solid waste disposal requirements, have occurred such that the Company determines that use of the Project is no longer required or desirable;

(v) the Loan Agreement has become void or unenforceable or impossible of performance by reason of any changes in the Constitution of the Commonwealth of Kentucky or the Constitution of the United States of America or by reason of legislative or administrative action (whether state or federal) or any final decree, judgment or order of any court or administrative body, whether state or federal; or

(vi) a final order or decree of any court or administrative body after the issuance of the Bonds requires the Company to cease a substantial part of its operation at the generating station where the Project is located to such extent that the Company will be prevented from carrying on its normal operations at such generating station for a period of six months.

Extraordinary Optional Redemption in Whole or in Part. The Bonds are also subject to redemption in whole or in part at 100% of the principal amount thereof plus accrued interest to the redemption date at the option of the Company in an amount not to exceed the net proceeds received from insurance or any condemnation award received by the Issuer or the Company in the event of damage, destruction or condemnation of all or a portion of the Project, subject to receipt of an opinion of Bond Counsel that such redemption will not adversely affect the exclusion of interest on any of the Bonds from gross income for federal income tax purposes, and such net proceeds must be applied to reimburse the Credit Facility Issuer for drawings under the Credit Facility to redeem the Bonds. See "Summary of the Loan Agreement — Maintenance; Damage, Destruction and Condemnation." Such redemption may occur at any time, provided that if such event occurs while the Interest Rate Mode for the Bonds is the Daily Rate, Weekly Rate, Flexible Rate or Semi-Annual Rate, such redemption must occur on a date on which the Bonds are otherwise subject to optional redemption as described above.

Mandatory Redemption; Determination of Taxability. The Bonds are required to be redeemed by the Issuer, in whole, or in such part as described below, at a redemption price equal to 100% of the principal amount thereof, without redemption premium, plus accrued interest, if any, to the redemption date, within 180 days following a "Determination of Taxability." As used herein, a "Determination of Taxability" means the receipt by the Trustee of written notice from a current or former registered owner of a Bond or from the Company or the Issuer of (A) the issuance of a published or private ruling or a technical advice memorandum by the Internal Revenue Service in which the Company participated or has been given the opportunity to participate, and which ruling or memorandum the Company, in its discretion, does not contest or from which no further right of administrative or judicial review or appeal exists, or (B) a final determination from which no further right of appeal exists of any court of competent jurisdiction in the United States in a proceeding in which the Company has participated or has been a party, or has been given the opportunity to participate or be a party, in each case, to the effect that as a result of a failure by the Company to perform or observe any covenant or agreement or the inaccuracy of any representation contained in the Loan Agreement or any other agreement or certificate delivered in connection with the Bonds, the interest on the Bonds is included in the gross income of the owners thereof for federal income tax purposes, other than with respect to a person who is a "substantial user" or a "related person" of a substantial user within the meaning of the Section 147 of Internal Revenue Code of 1986, as amended (the "Code"); provided, however, that no such Determination of Taxability shall be considered to exist as a result of the Trustee receiving notice from a current or former registered owner of a Bond or from the Issuer unless (A) the Issuer or the registered owner or former registered owner of the Bond involved in such proceeding or action (1) gives the Company and the Trustee prompt notice of the commencement thereof, and (2) (if the Company agrees to pay all expenses in connection therewith) offers the Company the opportunity to control unconditionally the defense thereof, and (B) either (1) the Company does not agree within 30 days of receipt of such offer to pay such expenses and liabilities and to control such defense, or (2) the Company shall exhaust or choose not to exhaust all available proceedings for the contest, review, appeal or rehearing of such decree, judgment or action which the Company determines to be appropriate. No Determination of Taxability described above will result from the inclusion of interest on any Bond in the computation of minimum or indirect taxes. All of the Bonds are required to be redeemed upon a Determination of Taxability as described above unless, in the opinion of Bond Counsel, redemption of a portion of such Bonds would have the result that interest payable on the remaining Bonds outstanding after the redemption would not be so included in any such gross income.

In the event any of the Issuer, the Company or the Trustee has been put on notice or becomes aware of the existence or pendency of any inquiry, audit or other proceedings relating to the Bonds being conducted by the Internal Revenue Service, the party so put on notice is required to give immediate written notice to the other parties of such matters. Promptly upon learning of the occurrence of a Determination of Taxability (whether or not the same is being contested), or any of the events described above, the Company is required to give notice thereof to the Trustee and the Issuer.

If the Internal Revenue Service or a court of competent jurisdiction determines that the interest paid or to be paid on any Bond (except to a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) is or was includable in the gross income of the recipient for federal income tax purposes for reasons other than as a result of a failure by the Company to perform or observe any of its covenants, agreements or representations in the Loan Agreement or any other agreement or certificate delivered in connection therewith, the Bonds are not subject to redemption. In such circumstances, Bondholders would continue to hold their Bonds, receiving principal and interest at the applicable rate as and when due, but would be required to include such interest payments in gross income for federal income tax purposes. Also, if the lien of the Indenture is discharged or defeased prior to the occurrence of a final Determination of Taxability, Bonds will not be redeemed as described herein.

General Redemption Terms. So long as a Credit Facility is in effect in respect of the Bonds, the redemption price (including accrued interest) will be paid from drawings under such Credit Facility or from moneys which otherwise constitute Available Moneys under the Indenture. Notice of redemption will be given by mailing a redemption notice by first class mail to the registered owners of the Bonds to be redeemed not less than 30 days (15 days if the Interest Rate Mode for the Bonds is the Dutch Auction Rate, the Daily Rate, the Weekly Rate or the Flexible Rate) but not more than 60 days prior to the redemption date. Any notice mailed as provided in the Indenture will be conclusively presumed to have been given, irrespective of whether the owner receives the notice. Failure to give any such notice by mailing or any defect therein in respect of any Bond will not affect the validity of any proceedings for the redemption of any other Bond. No further interest will accrue on the principal of any Bond called for redemption after the redemption date if funds sufficient for such redemption have been deposited with the Paying Agent as of the redemption date. So long as the Bonds are held in book-entry-only form, all redemption notices will be sent only to Cede & Co.

Book-Entry-Only System

Portions of the following information concerning DTC and DTC's book-entry-only system have been obtained from DTC. The Issuer, the Company and the Remarketing Agent make no representation as to the accuracy of such information.

Initially, DTC will act as securities depository for the Bonds and the Bonds initially will be issued solely in book-entry-only form to be held under DTC's book-entry-only system, registered in the name of Cede & Co. (DTC's partnership nominee). One fully registered bond in the aggregate principal amount of the Bonds will be deposited with DTC.

DTC, the world's largest depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934 (the "Exchange Act"). DTC holds and provides asset servicing for over 2.2 million issues of U.S. and non-U.S. equity, corporate and municipal debt issues, and money market instruments from over 100 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC, in turn, is owned by a number of Direct Participants of DTC and Members of the National Securities Clearing Corporation, Fixed Income Clearing Corporation, and Emerging Markets Clearing Corporation (NSCC, FICC and EMCC, also subsidiaries of DTCC), as well as by the New York Stock Exchange, Inc., the American Stock Exchange LLC and the National Association of Securities Dealers, Inc. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants" and, together with "Direct Participants," "Participants"). DTC has Standard & Poor's highest rating: AAA. The DTC Rules applicable to its Participants are on file with the SEC. More information about DTC can be found at www.dtcc.com and www.dtc.org.

Purchases of the Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser of each Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Bonds are to be accomplished by entries made on the books of Direct or Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the Bonds, except in the event that use of the book-entry system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of Bonds with DTC and their registration in the name of Cede & Co. or such other nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Redemption notices shall be sent to DTC. If less than all of the Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant to be redeemed.

Neither DTC nor Cede & Co. (nor such other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Issuer as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal and interest payments on the Bonds will be made to Cede & Co. or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts, upon DTC's receipt of funds and corresponding detail information from the Issuer or the Trustee on the payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC nor its nominee, the Trustee, the Company or the Issuer, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Issuer or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

A Beneficial Owner shall give notice to elect to have its Bonds purchased or tendered, through its Participant, to the Tender Agent, and shall effect delivery of such Bonds by causing the Direct Participant to transfer the Participant's interest in the Bonds, on DTC's records, to the Tender Agent. The requirement for physical delivery of Bonds in connection with a demand for purchase or a mandatory purchase will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on DTC's records and followed by a book-entry credit of tendered Bonds to the Tender Agent's DTC account.

DTC may discontinue providing its services as securities depository with respect to the Bonds at any time by giving reasonable notice to the Issuer, the Company, the Tender Agent and the Trustee, or the Issuer, at the request of the Company, may remove DTC as the securities depository for the Bonds. Under such circumstances, in the event that a successor securities depository is not obtained, bond certificates are required to be delivered as described in the Indenture (see "— Revision of Book-Entry-Only System; Replacement Bonds" below). The Beneficial Owner, upon registration of certificates held in the Beneficial Owner's name, will become the registered owner of the Bonds.

So long as Cede & Co. is the registered owner of the Bonds, as nominee of DTC, references herein to the registered owners of the Bonds will mean Cede & Co. and will not mean the Beneficial Owners. Under the Indenture, payments made by the Trustee to DTC or its nominee will satisfy the Issuer's obligations under the Indenture, the Company's obligations under the Loan Agreement, to the extent of the payments so made. Beneficial Owners will not be, and will not be considered by the Issuer or the Trustee to be, and will not have any rights as, owners of Bonds under the Indenture.

The Trustee and the Issuer, so long as a book-entry-only system is used for the Bonds, will send any notice of redemption or of proposed document amendments requiring consent of registered owners and any other notices required by the document (including notices of Conversion and mandatory purchase) to be sent to registered owners only to DTC (or any successor securities depository) or its nominee. Any failure of DTC to advise any Direct Participant, or of any Direct Participant or Indirect Participant to notify the Beneficial Owner, of any such notice and its content or effect will not affect the validity of the redemption of the Bonds called for redemption, the document amendment, the Conversion, the mandatory purchase or any other action premised on that notice.

The Issuer, the Company, the Trustee and the Remarketing Agent cannot and do not give any assurances that DTC will distribute payments on the Bonds made to DTC or its nominee as the registered owner or any redemption or other notices, to the Participants, or that the Participants or others will distribute such payments or notices to the Beneficial Owners, or that they will do so on a timely basis, or that DTC will serve and act in the manner described in this Reoffering Circular.

THE ISSUER, THE COMPANY, THE REMARKETING AGENT AND THE TRUSTEE WILL HAVE NO RESPONSIBILITY OR OBLIGATION TO ANY DIRECT PARTICIPANT, INDIRECT PARTICIPANT OR ANY BENEFICIAL OWNER OR ANY OTHER PERSON NOT SHOWN ON THE REGISTRATION BOOKS OF THE TRUSTEE AS BEING A REGISTERED OWNER WITH RESPECT TO: (1) THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC OR ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT; (2) THE PAYMENT OF ANY AMOUNT DUE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER IN RESPECT OF THE PRINCIPAL AMOUNT OR REDEMPTION OR PURCHASE PRICE OF OR INTEREST ON THE BONDS; (3) THE DELIVERY OF ANY NOTICE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER WHICH IS REQUIRED OR PERMITTED TO BE GIVEN TO REGISTERED OWNERS UNDER THE TERMS OF THE INDENTURE; (4) THE SELECTION OF THE BENEFICIAL OWNERS TO RECEIVE PAYMENT IN THE EVENT OF ANY PARTIAL REDEMPTION OF THE BONDS; OR (5) ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC AS REGISTERED OWNER.

<u>Revision of Book-Entry-Only System; Replacement Bonds</u>. In the event that DTC determines not to continue as securities depository or is removed by the Issuer, at the direction of the Company, as securities depository, the Issuer, at the direction of the Company, may appoint a successor securities depository reasonably acceptable to the Trustee. If the Issuer does not or is unable to appoint a successor securities depository, the Issuer will issue and the Trustee will authenticate and deliver fully registered Bonds, in authorized denominations, to the assignees of DTC or their nominees.

In the event that the book-entry-only system is discontinued, the following provisions will apply. The Bonds may be issued in denominations of $50,000 and integral multiples thereof, if the Interest Rate Mode is the Dutch Auction Rate; in denominations of $5,000 and integral multiples thereof, if the Interest Rate Mode is the Annual Rate or the Long Term Rate; in denominations of $100,000 and integral multiples of $5,000 in excess thereof, if the Interest Rate Mode is the Flexible Rate; and in denominations of $100,000 and integral multiples thereof, if the Interest Rate Mode is the Daily Rate, the Weekly Rate or the Semi-Annual Rate. Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the principal office of the Bond Registrar, accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond during the fifteen days before any mailing of a notice of redemption, after such Bond has been called for redemption in whole or in part, or after such Bond has been tendered or deemed tendered for optional or mandatory purchase as described under "— Purchases of Bonds on Demand of Owner" and "— Mandatory Purchases of Bonds." Registration of transfers and exchanges will be made without charge to the owners of Bonds, except that the Bond Registrar may require any owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

Security

Payment of the principal of and interest and any premium on the Bonds are secured by an assignment by the Issuer to the Trustee of the Issuer's interest in and to the Loan Agreement and all payments to be made pursuant thereto (other than certain indemnification and expense payments and notification rights). Pursuant to the Loan Agreement, the Company will agree to pay, among other things, amounts sufficient to pay the aggregate principal amount of and premium, if any, on the Bonds, together with interest thereon as and when the same become due. The Company further will agree to make payments of the purchase price of the Bonds tendered for purchase to the extent that funds are not otherwise available therefor under the provisions of the Indenture.

The Bonds are unsecured general obligations of the Company, ranking on a parity with the Company's obligations under the Loan Agreement to make payments on the Bonds.

The Letter of Credit

The following summarizes certain provisions of the Letter of Credit and the Reimbursement Agreement, to which reference is made for the detailed provisions thereof. Unless otherwise defined in this Reoffering Circular, capitalized terms in the following summary are used as defined in the Letter of Credit and the Reimbursement Agreement. The Company is permitted under the Indenture to deliver an Alternate Credit Facility to replace the Letter of Credit. Any such Alternate Credit Facility must meet certain requirements described in the Indenture.

The Letter of Credit

The Letter of Credit will be an irrevocable transferable direct pay letter of credit issued by the Bank in order to provide additional security for the payment of principal of, purchase price of, interest on and premium, if applicable, on any date when payments under the Bonds are due, including principal and interest payments and payments upon tender, redemption, acceleration or maturity of the Bonds. The Letter of Credit will provide for direct payments to or upon the order of the Trustee as set forth in the Letter of Credit in amounts sufficient to pay to or upon the order of the Trustee, upon request and in accordance with the terms thereof.

The Letter of Credit will be issued in an amount equal to the aggregate principal amount of the outstanding Bonds, plus an amount that represents interest accrued thereon at an assumed rate of 10% per annum for 45 days (the "Credit Amount"). The Trustee, upon compliance with the terms of the Letter of Credit, is authorized to draw up to (a) an amount sufficient (i) to pay principal of the Bonds, when due, whether at maturity or upon redemption or acceleration, and (ii) to pay the portion of the purchase price of the Bonds delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed (a “Liquidity Drawing”) equal to the principal amount of the Bonds, plus (b) an amount not to exceed 45 days of accrued interest on such Bonds at an assumed rate of 10% per annum (i) to pay interest on the Bonds, when due, and (ii) to pay the portion of the purchase price of the Bonds, delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed, equal to the interest accrued, if any, on the Bonds.

The amount available under the Letter of Credit will be automatically reduced by the amount of any drawing thereunder, subject to reinstatement as described below. With respect to a drawing by the Trustee solely to pay interest on the Bonds on an Interest Payment Date, the amount available under the Letter of Credit will be automatically reinstated in the amount of such drawing effective on the earlier of (i) receipt by the Bank from the Company of reimbursement of any drawing solely to pay interest in full or (ii) at the opening of business on the eleventh calendar day after the date the Bank honors such drawing, unless the Trustee has received written notice from the Bank by the tenth calendar day after the date the Bank honors such drawing the Bank is not so reinstating the available amount due to the Company’s failure to reimburse the Bank for such drawing in full, or that an event of default has occurred and is continuing under the Reimbursement Agreement and, in either case, directing, an acceleration of the Bonds pursuant to the Indenture. With respect to a Liquidity Drawing under the Letter of Credit, the amount available under the Letter of Credit will be automatically reduced by the principal amount of the Bonds purchased with the proceeds of such drawing plus the amount of accrued interest on such Bonds. In the event of the remarketing of the Bonds purchased with the proceeds of a Liquidity Drawing, the amount available under the Letter of Credit will be automatically reinstated upon receipt by the Bank or the Trustee on the Bank’s behalf of an amount equal to such principal amount plus accrued interest.

The Letter of Credit will terminate on the earliest to occur of:

(a) the Bank’s close of business on December 16, 2009 (such date, as extended from time to time in accordance with the Letter of Credit is defined as the “Stated Expiration Date”);

(b) the Bank’s close of business on the date which is five Business Days following the date of receipt by the Bank of a certificate from the Trustee certifying that (a) no Bonds remain Outstanding within the meaning of the Indenture, (b) all drawings required to be made under the Indenture and available under the Letter of Credit have been made and honored, (c) an Alternate Credit Facility has been delivered to the Trustee in accordance with the Indenture to replace the Letter of Credit or (d) all of the outstanding Bonds were converted to Bonds bearing interest at a rate other than the Daily Rate or the Weekly Rate;

(c) the Bank’s close of business on the date of receipt by the Bank of a certificate from the Trustee confirming that the Trustee is required to terminate the Letter of Credit in accordance with the terms of the Indenture; or

(d) the date on which the Bank receives and honors an acceleration drawing certificate.

The Reimbursement Agreement

Pursuant to the Reimbursement Agreement, the Company is obligated to reimburse the Bank for all amounts drawn under the Letter of Credit, and to pay interest on all such amounts. The Company has also agreed to pay the Bank a periodic fee for issuing and maintaining the Letter of Credit.

The Reimbursement Agreement imposes various covenants and agreements, including various financial and operating covenants, on the Company. Such covenants include, but are not limited to, covenants relating to (i) inspection of the books and financial records of the Company; (ii) creation of liens; (iii) liquidations, mergers, consolidations or sales of all or substantially all of the Company's assets; and (iv) disposition of assets. Any such covenants may be amended, waived or modified at any time by the Bank and without the consent of the Trustee or the holders of the Bonds. Under certain circumstances, the failure of the Company to comply with such covenants may result in a mandatory tender or acceleration of the Bonds.

The following events will constitute an "event of default" under the Reimbursement Agreement:

(a) nonpayment of certain fees and other amounts required to be paid or reimbursed by the Company under the Reimbursement Agreement to the Bank within five days after the same was required to be paid;

(b) any representation or warranty made or deemed made by or on behalf of the Company or any of its Significant Subsidiaries to the Bank under or in connection with the Reimbursement Agreement or any other Transaction Document, any advance or any certificate or information delivered pursuant to or in connection with the Reimbursement Agreement or any other Transaction Document, was false or misleading in any material respect as of the time it was made or furnished;

(c) an "event of default" (not due to the Bank's failure to properly honor a drawing on the Letter of Credit) occurred under the Indenture or any of the other Transaction Documents and any applicable grace period has expired;

(d) the breach by the Company or any of its Significant Subsidiaries of any of the terms or provisions of certain covenants contained in the Reimbursement Agreement including, but not limited to, covenants relating to the provision of notice to the Bank regarding an "event of default" or "default" under the Reimbursement Agreement, the corporate existence and license or qualification and good standing of the Company in jurisdictions in which it owns or leases property, the creation of liens, the liquidation, merger, consolidation or sale of all or substantially all of the assets of the Company and the disposition of assets;

(e) the breach by the Company or any of its Significant Subsidiaries (other than a breach which constitutes a "default" described above) of any of the terms or provisions of the Reimbursement Agreement or any Security Document that is not remedied within thirty (30) days after an executive officer of the Company has actual knowledge of such default or written notice of such default has been given to the Company by the Bank;

(f) the Bonds cease to be valid for any reason;

(g) a default or event of default has occurred at any time under the terms of any other agreement involving borrowed money or the extension of credit or any other Indebtedness under which the Company or any of its Significant Subsidiaries may be obligated for the payment of $50,000,000 or more in the aggregate, and such breach, default or event of default continues beyond any period of grace permitted with respect thereto and as a result thereof such Indebtedness is accelerated, becomes due or is otherwise required to be repurchased or redeemed prior to the scheduled date of maturity thereof;

(h) a proceeding has been instituted in a court having jurisdiction in the premises seeking a decree or order for relief in respect of the Company or any Significant Subsidiary in an involuntary case under any applicable bankruptcy, insolvency, reorganization or other similar law now or hereafter in effect, or for the appointment of a receiver, liquidator, assignee, custodian, trustee, sequestrator, conservator (or similar official) of the Company or any Significant Subsidiary for any substantial part of its property, or for the winding-up or liquidation of its affairs, and such proceeding shall remain undismissed or unstayed and in effect for a period of sixty (60) consecutive days; such court shall enter a decree or order granting any of the relief sought in such proceeding; or the Company or any Significant Subsidiary shall consent, approve or otherwise acquiesce in any of the actions sought in such proceeding;

(i) the Company or any Significant Subsidiary shall commence a voluntary case under any applicable bankruptcy, insolvency, reorganization or other similar law now or hereafter in effect, shall consent to the entry of an order for relief in an involuntary case under any such law, or shall consent to the appointment or taking possession by a receiver, liquidator, assignee, custodian, trustee, sequestrator, conservator (or other similar official) of itself or for any substantial part of its property or shall make a general assignment for the benefit of creditors, or shall fail generally to pay its debts as they become due, or shall take any action in furtherance of any of the foregoing;

(j) without the application, approval or consent of the Company or any of its Significant Subsidiaries, a receiver, trustee, examiner, liquidator or similar official shall be appointed for the Company or any of its Significant Subsidiaries, or for any substantial portion of its Property, or a proceeding described in paragraph (h) above has been instituted against the Company or any of its Significant Subsidiaries, and such appointment continues undischarged or such proceeding continues undismissed or unstayed for a period of 60 consecutive days;

(k) any of the following occurs: (i) any Reportable Event which constitutes grounds under Section 4042 of ERISA for the termination of any Plan by the PBGC or the appointment of a trustee to administer or liquidate any Plan, shall have occurred and be continuing; (ii) a notice of intent to terminate any Plan shall have been filed with the

PBGC under Section 4041 of ERISA; (iii) the PBGC shall give notice under Section 4042 of ERISA of its intent to institute proceedings to terminate any Plan or Plans or to appoint a trustee to administer or liquidate any Plan; (iv) the Company or any member of the ERISA Group shall fail to make any contributions when due to a Plan or a Multiemployer Plan; (v) the Company or any member of the ERISA Group shall make any amendment to a Plan with respect to which security is required under Section 307 of ERISA; (vi) the Company or any member of the ERISA Group shall withdraw completely or partially from a Multiemployer Plan pursuant to Subtitle E of Title IV of ERISA; or (vii) the Company or any member of the ERISA Group shall withdraw within the meaning of Section 4063 of ERISA (or shall be deemed under Section 4062(e) of ERISA to withdraw) from a Multiple Employer Plan; and, with respect to any of such events specified in clause (i), (ii), (iii), (iv), (v), (vi) or (vii), such occurrence would be reasonably likely to result in a Material Adverse Effect;

(l) any final judgment(s) or order(s) for the payment of money shall be entered against the Company or any of its Significant Subsidiaries by a court having jurisdiction in the premises which judgment is not discharged, vacated, bonded or stayed pending appeal within a period of thirty (30) days from the date of entry if the aggregate uninsured amount of all such judgments and orders exceeds $50,000,000;

(m) the Company or any of its Significant Subsidiaries ceases to conduct business (other than as permitted hereunder) or the Company is enjoined, restrained or in any way prevented by court order from conducting all or any material part of its business and such injunction, restraint or other preventive order is not dismissed within thirty (30) days after the entry thereof; or

(n) E.ON AG fails to own, directly or indirectly, at least seventy-five percent (75%) of the outstanding Voting Capital of the Company.

For purposes of the foregoing:

“Bond Documents” means the Indenture, the Custody Agreement, the Loan Agreement, the Bonds and the Remarketing Agreement.

“Material Adverse Effect” means (i) a material adverse change in the business, property, condition (financial or otherwise), operations or results of operations of the Company and its subsidiaries taken as a whole, (ii) a material adverse change in the ability of the Company to perform its obligation under the Transaction Documents or (iii) a material adverse change in the validity or enforceability of any of the Transaction Documents or the rights or remedies of the Bank thereunder.

“Security Documents” means the Custody, Pledge and Security Agreement dated as of December 17, 2008 among the Trustee, the Company and the Bank with respect to any Bond purchased during the period from and including the date of its purchase with proceeds of a Liquidity Drawing to but excluding the date on which such Bond is purchased by any person as a result of a remarketing of such Bond pursuant to the Remarketing Agreement and the Indenture.

"Transaction Documents" means, collectively, the Reimbursement Agreement, Bond Documents, the Security Documents and all other operative documents relating to the issuance, sale and securing of the Bonds (including without limitation any document(s) or instrument(s) through which the Bonds are now or hereafter collateralized, such as mortgages, security agreements, etc.).

Summary of the Loan Agreement

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the Loan Agreement. This description is only a summary and does not purport to be complete and definitive. Reference is made to the Loan Agreement for the detailed provisions thereof.

General

The Loan Agreement initially commenced as of its initial date and is amended and restated as of September 1, 2008 and will end on the earliest to occur of May 1, 2023, or the date on which all of the Bonds shall have been fully paid or provision has been made for such payment pursuant to the Indenture. See "Summary of the Indenture — Discharge of Indenture."

The Company has agreed to repay the loan pursuant to the Loan Agreement by making timely payments to the Trustee in sufficient amounts to pay the principal of, premium, if any, and interest required to be paid on the Bonds on each date upon which any such payments are due. The Company has also agreed to pay (a) the agreed upon fees and expenses of the Trustee, the Bond Registrar, any Tender Agent and any Paying Agent appointed under the Indenture, (b) the expenses in connection with any redemption of the Bonds and (c) the reasonable expenses of the Issuer.

The Company covenants and agrees with the Issuer that it will cause the purchase of tendered Bonds that are not remarketed in accordance with the Indenture and, to that end, the Company shall cause funds to be made available to the Tender Agent at the times and in the manner required to effect such purchases in accordance with the Indenture; provided, however, that the obligation of the Company to make any such payment will be reduced by the amount of (A) moneys paid by the Remarketing Agent as proceeds of the remarketing of such Bonds by the Remarketing Agent; (B) moneys drawn under a Credit Facility, if any, for the purpose of paying such purchase price and (C) other moneys made available by the Company (see "Summary of the Bonds — Remarketing and Purchase of Bonds").

All payments to be made by the Company to the Issuer pursuant to the Loan Agreement (except the reasonable out-of-pocket expenses of the Issuer, the Trustee, the Paying Agent, the Bond Registrar, the Tender Agent and amounts related to indemnification) have been assigned by the Issuer to the Trustee, and the Company will pay such amounts directly to the Trustee. The obligations of the Company to make the payments pursuant to the Loan Agreement are absolute and unconditional.

Maintenance of Tax Exemption

The Company and the Issuer have agreed not to take any action that would result in the interest paid on the Bonds being included in gross income of any Bondholder (other than a holder who is a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) for federal income tax purposes or that adversely affects the validity of the Bonds.

Payment of Taxes

The Company has agreed to pay certain taxes and other governmental charges that may be lawfully assessed, levied or charged against or with respect to the Project (see, however, subparagraph (i) under "Summary of the Bonds — Redemptions — Extraordinary Optional Redemption in Whole"). The Company may contest such taxes or other governmental charges unless the security provided by the Indenture would be materially endangered.

Maintenance; Damage, Destruction and Condemnation

So long as any Bonds are outstanding, the Company will maintain the Project or cause the Project to be maintained in good working condition and will make or cause to be made all proper repairs, replacements and renewals necessary to continue to constitute the Project as solid waste disposal facilities under Section 142(a)(6) of the Code and the Act. However, the Company will have no obligation to maintain, repair, replace or renew any portion of the Project, the maintenance, repair, replacement or renewal of which becomes uneconomical to the Company because of certain events, including damage or destruction by a cause not within the Company's control, condemnation of the Project, change in government standards and regulations, economic or other obsolescence or termination of operation of generating facilities to the Project.

The Company, at its own expense, may remodel the Project or make substitutions, modifications and improvements to the Project as it deems desirable, which remodeling, substitutions, modifications and improvements will be deemed, under the terms of the Loan Agreement to be a part of the Project. The Company may not, however, change or alter the basic nature of the Project or cause it to lose its status under Section 142(a)(6) of the Code and the Act.

If, prior to the payment of all Bonds outstanding, the Project or any portion thereof is destroyed, damaged or taken by the exercise of the power of eminent domain and the Issuer or the Company receives net proceeds from insurance or a condemnation award in connection therewith, the Company must (i) cause such net proceeds to be used to repair or restore the Project or (ii) reimburse the Credit Facility Issuer for drawings under the Credit Facility for the redemption of the Bonds in whole or in part at their principal amount, which, by the opinion of Bond Counsel, will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes. See "Summary of the Bonds — Redemptions — Extraordinary Optional Redemption in Whole or in Part."

Project Insurance

The Company will insure the Project in a manner consistent with general industry practice.

Assignment, Merger and Release of Obligations of the Company

The Company may assign the Loan Agreement, pursuant to an opinion of Bond Counsel that such assignment will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, without obtaining the consent of either the Issuer or the Trustee. Such assignment, however, shall not relieve the Company from primary liability for any of its obligations under the Loan Agreement and performance and observance of the other covenants and agreements to be performed by the Company. The Company may dispose of all or substantially all of its assets or consolidate with or merge into another corporation, provided the acquirer of the Company's assets or the corporation with which it shall consolidate with or merge into shall be a corporation or other business organization organized and existing under the laws of the United States of America or one of the states of the United States of America, shall be qualified and admitted to do business in the Commonwealth of Kentucky and shall assume in writing all of the obligations and covenants of the Company under the Loan Agreement.

Release and Indemnification Covenant

The Company will indemnify and hold the Issuer harmless against any expense or liability incurred, including attorneys' fees, resulting from any loss or damage to property or any injury to or death of any person occurring on or about or resulting from any defect in the Project or from any action commenced in connection with the financing thereof.

Events of Default

Each of the following events constitutes an "event of default" under the Loan Agreement:

(1) failure by the Company to pay the amounts required for payment of the principal of, including purchase price for tendered Bonds and redemption and acceleration prices, and interest accrued, on the Bonds, at the times specified therein taking into account any periods of grace provided in the Indenture and the Bonds for the applicable payment of interest on the Bonds (see "Summary of the Indenture — Defaults and Remedies");

(2) failure by the Company to observe and perform any covenant, condition or agreement, other than as referred to in paragraph (1) above, for a period of thirty days after written notice by the Issuer or Trustee, provided, however, that if such failure is capable of being corrected, but cannot be corrected in such 30-day period, it will not constitute an event of default under the Loan Agreement if corrective action with respect thereto is instituted within such period and is being diligently pursued; or

(3) certain events of bankruptcy, dissolution, liquidation, reorganization or insolvency of the Company.

Under the Loan Agreement, certain of the Company's obligations (other than the Company's obligation (i) not to permit any action which would result in interest paid on the Bonds being included in gross income for federal and Kentucky income taxes and (ii) to make loan payments and certain other payments under the provisions of the Loan Agreement) may be suspended if by reason of force majeure (as defined in the Loan Agreement) the Company is unable to carry out such obligations.

Remedies

Upon the happening of an event of default under the Loan Agreement, the Issuer may, among other things, take whatever action at law or in equity may appear necessary or desirable to collect the amounts then due and thereafter to become due, or to enforce performance and observance of any obligation, agreement or covenant of the Company, under the Loan Agreement.

Any amounts collected upon the happening of any such event of default shall be applied in accordance with the Indenture or, if the Bonds have been fully paid (or provision for payment thereof has been made in accordance with the Indenture), made available to the Company.

Options to Prepay, Obligation to Prepay

The Company may prepay the loan pursuant to the Loan Agreement, in whole or in part, on certain dates, at the prepayment prices as shown under the captions "Summary of the Bonds — Redemptions — Optional Redemption," "— Extraordinary Optional Redemption in Whole" and "— Extraordinary Optional Redemption in Whole or in Part." Upon the occurrence of the event described under the caption "Summary of the Bonds — Redemptions — Mandatory Redemption; Determination of Taxability," the Company shall be obligated to prepay the loan in an aggregate amount sufficient to redeem the required principal amount of the Bonds.

In each instance, the loan prepayment price shall be a sum sufficient, together with other funds deposited with the Trustee and available for such purpose, to redeem the requisite amount of the Bonds at a price equal to the applicable redemption price plus accrued interest to the redemption date, and to pay all reasonable and necessary fees and expenses of the Trustee, the Paying Agent and all other liabilities of the Company under the Loan Agreement accrued to the redemption date.

Amendments and Modifications

No amendment or modification of the Loan Agreement is permissible without the written consent of the Trustee. The Issuer and the Trustee may, however, without the consent of or notice to any Bondholders, enter into any amendment or modification of the Loan Agreement (i) which may be required by the provisions of the Loan Agreement or the Indenture, (ii) for the purpose of curing any ambiguity or formal defect or omission, (iii) in connection with any modification or change necessary to conform the Loan Agreement with changes and modifications in the Indenture or (iv) in connection with any other change which, in the judgment of the Trustee, does not adversely affect the Trustee or the Bondholders. Except for such amendments, the Loan Agreement may be amended or modified only with the consent of the Bondholders holding a majority in principal amount of the Bonds then outstanding (see

"Summary of the Indenture — Supplemental Indentures" for an explanation of the procedures necessary for Bondholder consent); provided, however, that the approval of the Bondholders holding 100% in principal amount of the Bonds then outstanding is necessary to effectuate an amendment or modification with respect to the Loan Agreement of the type described in clauses (i) through (iv) of the first sentence of the second paragraph of "Summary of the Indenture — Supplemental Indentures." Any amendments, changes or modification of the Loan Agreement that require the consent of the Bondholders must additionally be approved by the Credit Facility Issuer, if the Bonds are at the time secured by a Credit Facility. Additionally, so long as a Credit Facility is in place or while any amounts are outstanding under a Reimbursement Agreement, the Credit Facility Issuer must consent in writing to any amendment, change, or modification to the Agreement.

Summary of the Indenture

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the Indenture. This description is only a summary and does not purport to be complete and definitive. Reference is made to the Indenture for the detailed provisions thereof.

Security

Pursuant to the Indenture, the Issuer has assigned and pledged to the Trustee its interest in and to the Loan Agreement, including payments and other amounts due the Issuer thereunder, together with all moneys, property and securities from time to time held by the Trustee under the Indenture (with certain exceptions, including moneys held in or earnings on the Rebate Fund and the Purchase Fund). The Bonds are not directly secured by the Project.

No Pecuniary Liability of the Issuer

No provision, covenant or agreement contained in the Indenture or in the Loan Agreement, nor any breach thereof, shall give rise to any pecuniary liability of the Issuer or any charge upon its general credit or taxing powers. The Issuer has not obligated itself by making the covenants, agreements or provisions contained in the Indenture or in the Loan Agreement, except with respect to the Project and the application of the amounts assigned to payment of the principal of, premium, if any, and interest on the Bonds.

The Bond Fund

The payments to be made by the Company pursuant to the Loan Agreement to the Issuer and certain other amounts specified in the Indenture will be deposited into a Bond Fund established pursuant to the Indenture (the "Bond Fund") and will be maintained in trust by the Trustee. Moneys in the Bond Fund will be used for the payment of the principal of, premium, if any, and interest on the Bonds, and for the redemption of Bonds prior to maturity in the following order of priority: (i) proceeds of the Credit Facility, if any, deposited into the Bond Fund in accordance with the Indenture and (ii) any other moneys provided by or on behalf of the Company. Any moneys held in the Bond Fund will be invested by the Trustee at the specific written direction of the Company in certain Governmental Obligations, investment-grade corporate obligations and other investments permitted under the Indenture.

So long as a Credit Facility is then held by the Trustee and there is no default in the payment of principal or redemption price of or interest on the Bonds, any amounts in the Bond Fund provided by or on behalf of the Company will be paid to the Credit Facility Issuer to the extent of any amounts that the Company owes the Credit Facility Issuer pursuant to the Reimbursement Agreement. Any amounts remaining in the Bond Fund (first, from the proceeds of the Credit Facility, and second, from the moneys provided by or on behalf of the Company) after payment in full of the principal or redemption price of and interest on the Bonds (or provision for payment thereof) and payment of any outstanding fees and expenses of the Trustee (including its reasonable attorney fees and expenses) will be paid, first, to the Credit Facility Issuer, to the extent of any amounts that the Company owes the Credit Facility Issuer pursuant to the Reimbursement Agreement and, second, to the Company. Any amounts remaining in the Bond Fund (i) after all of the outstanding Bonds have been paid and discharged, (ii) after payment of all fees, charges and expenses to the Issuer, the Trustee, the Registrar and the Paying Agent and of all other amounts required to be paid under the Indenture and the Loan Agreement and (iii) after the receipt by the Trustee of the written request of the Company for such payment, will be paid to the Credit Facility Issuer, if any, to the extent of any amounts that the Company owes to such Credit Facility Issuer pursuant to the Reimbursement Agreement, and then to the Company to the extent that those moneys are in excess of the amounts necessary to effect the payment and discharge of the outstanding Bonds.

The Rebate Fund

A Rebate Fund has been created by the Indenture (the “Rebate Fund”) and is maintained as a separate fund free and clear of the lien of the Indenture. The Issuer, the Trustee and the Company have agreed to comply with all rebate requirements of the Code and, in particular, the Company has agreed that if necessary, it will deposit in the Rebate Fund any such amount as is required under the Code. However, the Issuer, the Trustee and the Company may disregard the Rebate Fund provisions to the extent that they receive an opinion of Bond Counsel that such failure to comply will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes.

Discharge of Indenture

When all the Bonds and all fees and charges accrued and to accrue of the Trustee and the Paying Agent have been paid or provided for, and when proper notice has been given to the Bondholders or the Trustee that the proper amounts have been so paid or provided for, and if the Issuer is not in default in any other respect under the Indenture, the Indenture shall become null and void. The Bonds will be deemed to have been paid and discharged when there have been irrevocably deposited with the Trustee moneys sufficient to pay the principal, premium, if any, and accrued interest on such Bonds to the due date (whether such date be by reason of maturity or upon redemption) or, in lieu thereof, Governmental Obligations have been deposited which mature in such amounts and at such times as will provide the funds necessary to so pay such Bonds, and when all reasonable and necessary fees and expenses of the Trustee and the Paying Agent have been paid or provided for.

Notwithstanding anything to the contrary, if any Bonds are rated by a rating service, no such Bonds will be deemed to have been paid and discharged by reason of any deposit pursuant to the Indenture, unless each such rating service has confirmed in writing to the Trustee that its rating will not be withdrawn or lowered as a result of any such deposit.

So long as the Company owes any amounts to the Credit Facility Issuer, if any, pursuant to the Reimbursement Agreement: (A) the lien of the Indenture may not be discharged; (B) such Credit Facility Issuer shall be subrogated to the extent of such amounts owed by the Company to such Credit Facility Issuer to all rights of the Bondholders to enforce the payment of the Bonds from the revenues and all other rights of the Bondholders under the Bonds, the Indenture and the Loan Agreement; (C) the Bondholders will be deemed paid to the extent of money drawn by the Trustee under the Credit Facility; and (D) subject to the Indenture, the Trustee will sign, execute and deliver all documents or instruments and do all things that may be reasonably required by the Credit Facility Issuer to effect the Credit Facility Issuer's subrogation of rights of enforcement and remedies set forth in the Indenture.

Defaults and Remedies

Each of the following events constitutes an "Event of Default" under the Indenture:

(a) failure to make payment of any installment of interest on any Bond (i) if such Bond bears interest at other than the Long Term Rate, within a period of one Business Day from the due date, and (ii) if such Bond bears interest at the Long Term Rate, within a period of five Business Days from the due date;

(b) failure to make punctual payment of the principal of, or premium, if any, on any Bond on the due date, whether at the stated maturity thereof, or upon proceedings for redemption, or upon the maturity thereof by declaration or if payment of the purchase price of any Bond required to be purchased pursuant to the Indenture is not made when such payment has become due and payable;

(c) failure of the Issuer to perform or observe any other of the covenants, agreements or conditions in the Indenture or in the Bonds which failure continues for a period of 30 days after written notice by the Trustee, provided, however, that if such failure is capable of being cured, but cannot be cured in such 30-day period, it will not constitute an event of default under the Indenture if corrective action in respect of such failure is instituted within such 30-day period and is being diligently pursued;

(d) the occurrence of an "event of default" under the Loan Agreement (see "Summary of the Loan Agreement — Events of Default");

(e) written notice from the Credit Facility Issuer to the Trustee of an event of default under the Reimbursement Agreement, by reason of which the Trustee has been directed to accelerate the Bonds; or

(f) if a Credit Facility is then held by the Trustee, on or before the close of business on the tenth calendar day following the honoring of a drawing under such Credit Facility to pay interest on the Bonds on an Interest Payment Date, written notice from the

Credit Facility Issuer to the Trustee that the interest component of the Credit Facility will not be reinstated.

Upon the occurrence of an Event of Default under clauses (a), (b), (e) or (f) above, the Trustee must: (i) declare the principal of all Bonds and interest accrued thereon to be immediately due and payable; (ii) declare all payments under the Loan Agreement to be immediately due and payable and enforce each and every other right granted to the Issuer under the Loan Agreement for the benefit of the Bondholders; and (iii) if a Credit Facility securing the Bonds is in effect, make an immediate drawing under the Credit Facility in accordance with its terms and deposit the proceeds of such drawing in the Bond Fund pending application to the payment of principal of the Bonds, subject to the provisions of the Indenture reserving to the Credit Facility Issuer the right to direct default proceedings and providing for termination of default proceedings upon certain occurrences.

Interest on the Bonds will cease to accrue on the date of issuance of the declaration of acceleration of payment of principal and interest on the Bonds.

In exercising such rights, the Trustee will take any action that, in the judgment of the Trustee, would best serve the interests of the registered owners. Upon the occurrence of an Event of Default under the Indenture, the Trustee may also proceed to pursue any available remedy by suit at law or in equity to enforce the payment of the principal of, premium, if any, and interest on the Bonds then outstanding.

If the Trustee recovers any moneys following an Event of Default, unless the principal of the Bonds shall have been declared due and payable, all such moneys shall be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent, (ii) to the payment of all interest then due on the Bonds and (iii) to the payment of unpaid principal and premium, if any, of the Bonds. If the principal of the Bonds has become due or has been accelerated, such moneys shall be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and (ii) to the payment of principal of and interest then due and unpaid on the Bonds. In each case, however, Trustee and Paying Agent fees or costs will not be payable from moneys derived from Credit Facility drawings, any remarketing proceeds or moneys constituting certain Available Moneys under the Indenture.

No Bondholder may institute any suit or proceeding in equity or at law for the enforcement of the Indenture unless an Event of Default has occurred of which the Trustee has been notified or is deemed to have notice, and registered owners holding not less than 25% in aggregate principal amount of Bonds then outstanding shall have made written request to the Trustee to proceed to exercise the powers granted under the Indenture or to institute such action in their own name and the Trustee shall fail or refuse to exercise its powers within a reasonable time after receipt of indemnity satisfactory to it.

Any judgment against the Issuer pursuant to the exercise of rights under the Indenture shall be enforceable only against specific assigned payments, funds and accounts under the Indenture in the hands of the Trustee. No deficiency judgment shall be authorized against the general credit of the Issuer.

No default under paragraph (c) above shall constitute an Event of Default until actual notice is given to the Issuer and the Company by the Trustee, or to the Issuer, the Company and the Trustee by the registered owners holding not less than 25% in aggregate principal amount of all Bonds outstanding or the Issuer and the Company shall have had thirty days after such notice to correct the default and failed to do so. If the default is such that it cannot be corrected within the applicable period but is capable of being cured, it will not constitute an Event of Default if corrective action is instituted within the applicable period.

Notwithstanding the foregoing, in addition to the rights of the Trustee and the Bondholders to direct proceedings as described above, if a Credit Facility is in effect, for so long as such Credit Facility is outstanding and the Credit Facility Issuer is not in default in its duties under the Indenture or the Credit Facility, the Credit Facility Issuer issuing will have the absolute right to direct all proceedings on behalf of the Bondholders of the Bonds. Additionally, if the Event of Default which has occurred is an Event of Default under paragraphs (e) or (f) above, the Credit Facility Issuer, if any, will have no right to direct the Trustee or the Bondholders with respect to any matters, including remedies, and the holders of a majority in aggregate principal amount of the Bonds then outstanding, will have the right, at any time, by an instrument or instruments in writing executed and delivered to the Trustee, to direct the time, method and place of conducting all proceedings to be taken in connection with the enforcement of the terms and conditions of the Indenture, or for the appointment of a receiver or any other proceedings hereunder; provided, that such direction shall not be otherwise than in accordance with the provisions of law and of the Indenture.

If an Event of Default has occurred under the Indenture due to failure by the Credit Facility Issuer, if any, to honor a properly presented and conforming drawing by the Trustee under the Credit Facility then in effect in accordance with the terms thereof, all obligations of the Trustee to the Credit Facility Issuer and all rights of such Credit Facility Issuer under the Indenture will be suspended until the earlier of the cure of such failure or all of the Bonds have been paid in full.

Waiver of Events of Default

Except as provided below, the Trustee may in its discretion waive any Event of Default under the Indenture and shall do so upon the written request of the registered owners holding a majority in principal amount of all Bonds then outstanding. If, after the principal of all Bonds then outstanding shall have been declared to be due and payable and prior to any judgment or decree for the appointment of a receiver or for the payment of the moneys due shall have been entered, (i) the Company has caused to be deposited with the Trustee a sum sufficient to pay all matured installments of interest upon all Bonds and the principal of and premium, if any, on any and all Bonds which shall have become due otherwise than by reason of such declaration and the expenses of the Trustee in connection with such default (with interest thereon as provided in the Indenture) and (ii) all Events of Default under the Indenture (other than nonpayment of the principal of Bonds due by said declaration) shall have been remedied, then such Event of Default shall be deemed waived and such declaration and its consequences rescinded and annulled by the Trustee. Such waiver, rescission and annulment shall be binding upon all Bondholders. No such waiver, rescission and annulment shall extend to or affect any subsequent Event of Default or impair any right or remedy consequent thereon.

The Trustee may not waive any default under clauses (e) or (f) above unless the Trustee has received in writing from the Credit Facility Issuer a written notice of full reinstatement of the full amount of the Credit Facility and a written rescission of the notice of the Event of Default.

Notwithstanding the foregoing, nothing in the Indenture shall affect the right of a registered owner to enforce the payment of principal of, premium, if any, and interest on the Bonds after the maturity thereof.

Supplemental Indentures

The Issuer and the Trustee may enter into indentures supplemental to the Indenture without the consent of or notice to, the Bondholders in order (i) to cure any ambiguity or formal defect or omission in the Indenture, (ii) to grant to the Trustee, as may lawfully be granted, additional rights for the benefit of the Bondholders, (iii) to subject to the Indenture additional revenues, properties or collateral, (iv) to permit qualification of the Indenture under any federal statute or state blue sky law, (v) to add additional covenants and agreements of the Issuer for the protection of the Bondholders or to surrender or limit any rights reserved to the Issuer, (vi) to make any modification or change to the Indenture which, in the sole judgment of the Trustee, does not adversely affect the Trustee or any Bondholder, (vii) to make amendments to provisions relating to federal income tax matters under the Code or other relevant provisions if, in the opinion of Bond Counsel, those amendments would not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, (viii) to make any modifications or changes to the Indenture necessary to provide the securing of a Credit Facility or Alternate Credit Facility or any liquidity or credit support of any kind for the security of the Bonds (including without limitation any line of credit, letter of credit, guaranty agreement or insurance coverage), including any modifications of the Indenture or the Agreement necessary to upgrade or maintain the then applicable ratings on the Bonds; or (ix) to permit the issuance of the Bonds in other than book-entry-only form or to provide changes to or for the book-entry system.

Subject to the consent of the Credit Facility Issuer, if any, exclusive of supplemental indentures for the purposes set forth in the preceding paragraph, the consent of registered owners holding a majority in principal amount of all Bonds then outstanding is required to approve any supplemental indenture, except no such supplemental indenture shall permit, without the consent of all of the registered owners of the Bonds then outstanding, (i) an extension of the maturity of the principal of or the interest on any Bond issued under the Indenture or a reduction in the principal amount of any Bond or the rate of interest or time of redemption or redemption premium thereon, (ii) a privilege or priority of any Bond or Bonds over any other Bond or Bonds, (iii) a reduction in the principal amount of the Bonds required for consent to such supplemental indenture or (iv) the deprivation of any registered owners of the lien of the Indenture.

If at any time the Issuer shall request the Trustee to enter into any supplemental indenture requiring the consent of the registered owners of the Bonds, the Trustee, upon being satisfactorily indemnified with respect to expenses, must notify all such registered owners. Such notice shall set forth the nature of the proposed supplemental indenture and shall state that copies thereof are on file at the principal office of the Trustee for inspection. If, within sixty days (or such longer period as shall be prescribed by the Issuer or the Company) following the mailing of such notice, the registered owners holding the requisite amount of the Bonds outstanding shall have consented to the execution thereof, no Bondholder shall have any right to object or question the execution thereof.

No supplemental indenture shall become effective unless the Company consents to the execution and delivery of such supplemental indenture. The Company shall be deemed to have consented to the execution and delivery of any supplemental indenture if the Trustee does not receive a notice of protest or objection signed by the Company on or before 4:30 p.m., local time in the city in which the principal office of the Trustee is located, on the fifteenth day after the mailing to the Company of a notice of the proposed changes and a copy of the proposed supplemental indenture.

Notwithstanding the foregoing, any Supplemental Indenture that requires the consent of the Bondholders that (i) is to become effective while a Credit Facility is in place or while any amounts are outstanding under any Reimbursement Agreement and (ii) adversely affects the Credit Facility Issuer will not become effective unless and until the Credit Facility Issuer consents in writing to the execution and delivery of such Supplemental Indenture.

Cancellation of Credit Facility; Delivery of Alternate Credit Facility

The Trustee will, at the written direction of the Company but subject to the conditions described in this paragraph and the receipt of an Opinion of Bond Counsel stating that the cancellation of such Credit Facility is authorized under the Indenture and under the Act and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, cancel any Credit Facility in accordance with the terms thereof which cancellation may be without substitution therefor or replacement thereof; provided, that any such cancellation will not become effective, surrender of such Credit Facility will not take place and that Credit Facility will not terminate, in any event, until (i) payment by the Credit Facility Issuer has been made for any and all drawings by the Trustee effected on or before such cancellation date (including, if applicable, any drawings for payment of the purchase price of Bonds to be purchased pursuant to the Indenture in connection with such cancellation) and (ii) if the Bonds are in an Long Term Rate Period, only if the then current Long Term Rate Period for the Bonds is ending on, or the Bonds are subject to optional redemption on, the Interest Payment Date immediately preceding the date of such cancellation. Upon written notice given by the Company to the Trustee at least 20 days (35 days if the Bonds are bearing interest at the Long Term Rate) prior to the date of cancellation of any Credit Facility of such cancellation and the effective date of such cancellation, the Trustee will surrender such Credit Facility to the Credit Facility Issuer by which it was issued on or promptly after the effective date of such cancellation in accordance with its terms; provided, that such notice will not be given in any event, if the purchase price of any Bonds to be purchased pursuant to the Indenture in connection with such cancellation includes any premium unless the Company has certified in such notice that the Trustee can draw under a Credit Facility (other than any Alternate Credit Facility being delivered in connection with such cancellation) on the purchase date related to such purchase of Bonds in an aggregate amount sufficient to pay the premium due upon such purchase of Bonds on such purchase date.

The Company may, at its option, provide for the delivery to the Trustee of an Alternate Credit Facility in replacement of any Credit Facility then in effect. At least 20 days (35 days if the Interest Rate on the Bonds is a Long Term Rate) prior to the date of delivery of an Alternate Credit Facility to the Trustee, the Company must give notice, which notice will also be given to the Remarketing Agent, of such replacement to the Trustee, together with an Opinion of Bond Counsel to the effect that the delivery of such Alternate Credit Facility to the Trustee is authorized under the Indenture and the Act and complies with the terms thereof and that the delivery of such Alternate Credit Facility will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. The Trustee will then accept such Alternate Credit Facility and surrender the previously held Credit Facility, if any, to the previous Credit Facility Issuer for cancellation promptly on or after the 5th day after the Alternate Credit Facility becomes effective; provided, however, that such Alternate Credit Facility must become effective on an Interest Payment Date and, if the Bonds are in a Long Term Rate Period, such Alternate Credit Facility may only become effective on either the last Interest Payment Date for such Long Term Rate Period or an Interest Payment Date on which the Bonds are subject to optional redemption. The notice given to the Trustee shall also be given to the Issuer, the then current Credit Facility Issuer, Moody's, if the Bonds are then rated by Moody's, and S&P, if the Bonds are then rated by S&P; provided that the notice will not be given if the purchase price of any Bonds to be purchased pursuant to the Indenture in connection with such cancellation includes any premium unless the Company has certified in such notice that the Trustee can draw under a Credit Facility then in effect on the purchase date related to such purchase of Bonds in an aggregate amount sufficient to pay the premium due upon such purchase of Bonds on such purchase date and until payment under the Credit Facility to be surrendered shall have been made for any and all drawings by the Trustee effected on or before the date of such surrender for cancellation (including, if applicable, any drawings for payment of the purchase price of Bonds to be purchased pursuant to the Indenture in connection with such cancellation).

Any Alternate Credit Facility delivered to the Trustee must be accompanied by an opinion of counsel to the issuer or provider of such Credit Facility stating that such Credit Facility is a legal, valid, binding and enforceable obligation of such issuer or obligor in accordance with its terms.

The Bonds will be subject to mandatory tender for purchase on the date of cancellation of a Credit Facility and on the date of the delivery of an Alternate Credit Facility. See "Summary of the Bonds — Mandatory Purchases of Bonds."

Enforceability of Remedies

The remedies available to the Trustee, the Issuer and the owners upon an event of default under the Loan Agreement or the Indenture are in many respects dependent upon judicial actions which are often subject to discretion and delay. Under existing constitutional and statutory law and judicial decisions, the remedies specified by the Loan Agreement or the Indenture may not be readily available or may be limited. The various legal opinions to be delivered concurrently with the delivery of the Bonds will be qualified as to the enforceability of the various legal instruments by limitations imposed by principles of equity, bankruptcy, reorganization, insolvency, moratorium or other similar laws affecting the rights of creditors generally.

Reoffering

Subject to the terms and conditions of the Remarketing and Bond Purchase Agreement (the "Remarketing Agreement"), between the Company and Morgan Stanley & Co. Incorporated, as Remarketing Agent, the Remarketing Agent has agreed to purchase and reoffer the Bonds delivered to the Paying Agent for purchase, at a price equal to 100% of the principal amount of the Bonds, plus accrued interest (if any), and in connection therewith will receive compensation in the amount of $32,250, plus reimbursement of certain expenses. Under the terms of the Remarketing Agreement, the Company has agreed to indemnify the Remarketing Agent against certain civil liabilities, including liabilities under federal securities laws.

In the ordinary course of their business, the Remarketing Agent and certain of its affiliates, have engaged, and may in the future engage, in investment banking or commercial banking transactions with the Company.

Tax Treatment

On May 19, 2000, the date of original issuance and delivery of the Bonds, Bond Counsel delivered its opinion stating that under existing law, including current statutes, regulations, administrative rulings and official interpretations, subject to the qualifications and exceptions set forth below, interest on the Bonds will be excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion will be expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person" as such terms are used in Section 147(a) of the Code. Interest on the Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. Bond Counsel further opined that, subject to the assumptions stated in the preceding sentence, (i) interest on the Bonds would be excluded from gross income of the owners thereof for Kentucky income tax purposes and (ii) the Bonds would be exempt from all ad valorem taxes in Kentucky. Such opinion has not been updated as of the date hereof and no continuing tax exemption opinion is expressed by Bond Counsel.

Bond Counsel also will deliver an opinion in connection with this reoffering to the effect that the delivery of the Letter of Credit (i) is authorized or permitted by Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act") and the Indenture and (ii) will not adversely affect the validity of the Bonds or any exclusion from gross income of interest on the Bonds for federal income tax purposes to which interest on the Bonds would otherwise be entitled.

The opinions of Bond Counsel as to the excludability of interest from gross income for federal income tax purposes were based upon and assumed the accuracy of certain representations of facts and circumstances, including with respect to the Project, which were within the knowledge of the Company and compliance by the Company with certain covenants and undertakings set forth in the proceedings authorizing the Bonds which are intended to assure that the Bonds are and will remain obligations the interest on which is not includable in gross income of the recipients thereof under the law in effect on the date of such opinion. Bond Counsel did not independently verify the accuracy of the certifications and representations made by the Company and the Issuer. On the date of the opinion and subsequent to the original delivery of the Bonds on May 19, 2000, such representations of facts and circumstances must be accurate and such covenants and undertakings must continue to be complied with in order that interest on the Bonds be and remain excludable from gross income of the recipients thereof for federal income tax purposes under existing law. Bond Counsel expressed no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents other than with the approval of Bond Counsel is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability.

Bond Counsel further opined that the Code prescribed a number of qualifications and conditions for the interest on state and local government obligations to be and to remain excluded from gross income for federal income tax purposes, some of which, including provisions for potential payments by the Issuers to the federal government, require future or continued compliance after issuance of the Bonds in order for the interest to be and to continue to be so excluded from the date of issuance. Noncompliance with certain of these requirements by the Company or the Issuer with respect to the Bonds could cause the interest on the Bonds to be included in gross income for federal income tax purposes and to be subject to federal income taxation retroactively to the date of their issuance. The Company and the Issuer each covenanted to take all actions required of each to assure that the interest on the Bonds shall be and remain excluded from gross income for federal income tax purposes, and not to take any actions that would adversely affect that exclusion.

The opinion of Bond Counsel as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds was subject to the following exceptions and qualifications:

(a) The Code also provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, Bond Counsel expressed no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Owners of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income tax credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of Section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income. Prospective purchasers of the Bonds should consult their own tax advisors regarding such matters and any other tax consequences of holding the Bonds.

From time to time, there are legislative proposals in Congress which, if enacted, could alter or amend one or more of the federal tax matters referred to above or could adversely affect the market value of the Bonds. It cannot be predicted whether or in what form any such proposal might be enacted or whether, if enacted, it would apply to obligations (such as the Bonds) issued prior to enactment.

The opinion of Bond Counsel relating to the reoffering of the Bonds in substantially the form in which it is expected to be delivered on the Reoffering Date, redated to the Reoffering Date, is attached as Appendix B-2.

Legal Matters

Certain legal matters in connection with the reoffering of the Bonds will be passed upon by Stoll Keenon Ogden PLLC, Louisville, Kentucky, Bond Counsel. Certain legal matters pertaining to the Company will be passed upon by Jones Day, Chicago, Illinois, and John R. McCall, Esq., Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer of the Company. Winston & Strawn LLP, Chicago, Illinois, will pass upon certain legal matters for the Remarketing Agent.

Continuing Disclosure

Because the Bonds are special and limited obligations of the Issuer, the Issuer is not an "obligated person" for purposes of Rule 15c2-12 (the "Rule") promulgated by the SEC under the Exchange Act, and does not have any continuing obligations thereunder. Accordingly, the Issuer will not provide any continuing disclosure information with respect to the Bonds or the Issuer.

In order to enable the Remarketing Agent to comply with the requirements of the Rule, the Company has covenanted in a continuing disclosure undertaking agreement delivered to the Trustee for the benefit of the holders of the Bonds (the "Continuing Disclosure Agreement") to provide certain continuing disclosure for the benefit of the holders of the Bonds. Under its Continuing Disclosure Agreement, the Company has covenanted to take the following actions:

(a) The Company will provide to each nationally recognized municipal securities information repository ("NRMSIR"), recognized by the SEC pursuant to the

Rule, and the state information depository, if any, of the Commonwealth of Kentucky (a "SID" and, together with the NRMSIR, a "Repository") recognized by the SEC (1) annual financial information of the type set forth in Appendix A to this Reoffering Circular (including any information incorporated by reference therein) and (2) audited financial statements prepared in accordance with generally accepted accounting principles, in each case not later than 120 days after the end of the Company's fiscal year.

(b) The Company will file in a timely manner with each NRMSIR or the Municipal Securities Rulemaking Board, and with the SID, if any, notice of the occurrence of any of the following events (if applicable) with respect to the Bonds, if material: (i) principal and interest payment delinquencies; (ii) non-payment related defaults; (iii) any unscheduled draws on debt service reserves reflecting financial difficulties; (iv) unscheduled draws on credit enhancement facilities reflecting financial difficulties; (v) substitution of credit or liquidity providers, or their failure to perform; (vi) adverse tax opinions or events affecting the tax-exempt status of the Bonds; (vii) modifications to rights of the holders of the Bonds; (viii) the giving of notice of optional or unscheduled redemption of any Bonds; (ix) defeasance of the Bonds or any portion thereof; (x) release, substitution, or sale of property securing repayment of the Bonds; and (xi) rating changes with respect to the Bonds or the Company or any obligated person, within the meaning of the Rule.

(c) The Company will file in a timely manner with each Repository notice of a failure by the Company to file any of the notices or reports referred to in paragraphs (a) and (b) above by the due date.

The Company may amend its Continuing Disclosure Agreement (and the Trustee shall agree to any amendment so requested by the Company that does not change the duties of the Trustee thereunder) or waive any provision thereof, but only with a change in circumstances that arises from a change in legal requirements, change in law, or change in the nature or status of the Company with respect to the Bonds or the type of business conducted by the Company; provided that the undertaking, as amended or following such waiver, would have complied with the requirements of the Rule on the date of issuance of the Bonds, after taking into account any amendments to the Rule as well as any change in circumstances, and the amendment or waiver does not materially impair the interests of the holders of the Bonds to which such undertaking relates, in the opinion of the Trustee or counsel expert in federal securities laws acceptable to both the Company and the Trustee, or is approved by the Beneficial Owners of a majority in aggregate principal amount of the outstanding Bonds. The Company acknowledges that its undertakings pursuant to the Rule described under this heading are intended to be for the benefit for the holders of the Bonds and shall be enforceable by the holders of those Bonds or by the Trustee on behalf of such holders. Any breach by the Company of these undertakings pursuant to the Rule will not constitute an event of default under the Indenture, the Loan Agreement or the Bonds.

This Reoffering Circular has been duly approved, executed and delivered by the Company.

KENTUCKY UTILITIES COMPANY

By: /s/ Daniel K. Arbough
Daniel K. Arbough
Treasurer

Appendix A

[DELETED AND REPLACED – SEE APPENDIX A TO SUPPLEMENT DATED MAY 2, 2011]

APPENDIX B

Opinion of Bond Counsel and
Form of Reoffering Opinion of Bond Counsel

APPENDIX B-1

Opinion of Bond Counsel dated May 19, 2000 relating to the Bonds

HARPER, FERGUSON & DAVIS
ATTORNEYS AT LAW
1730 MEIDINGER TOWER
462 SOUTH FOURTH AVENUE
LOUISVILLE, KENTUCKY 40202-3413

28 WEST FIFTH STREET
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LOUISVILLE OFFICE
(502) 582-3871
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COVINGTON OFFICE
(606) 491-0712
TELECOPIER (606) 491-0187

May 19, 2000

Re: $12,900,000 County of Mercer, Kentucky, Solid Waste Disposal Facility Revenue Bonds, 2000 Series A (Kentucky Utilities Company Project)

We hereby certify that we have examined certified copies of the proceedings of record of the County of Mercer, Kentucky (the "County"), acting by and through its Fiscal Court as its duly authorized governing body, preliminary to and in connection with the issuance by the County of its Solid Waste Disposal Facility Revenue Bonds, 2000 Series A (Kentucky Utilities Company Project), dated the date of the Bonds, in the aggregate principal amount of $12,900,000 (the "Bonds"). The Bonds will be issued under the provisions of Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act"), for the purpose of providing funds which will be used, with other funds provided by Kentucky Utilities Company (the "Company") for the current refunding of $12,900,000 aggregate principal amount of the County's Collateralized Solid Waste Disposal Facility Revenue Bonds (Kentucky Utilities Company Project) 1990 Series A, dated May 1, 1990 (the "Prior Bonds"), the proceeds of which were loaned to the Company to finance the construction of solid waste disposal facilities to serve the Brown Generating Station of the Company in Mercer County, Kentucky ("the Project") in order to provide for the collection, storage, treatment, processing and final disposal of solid waste, as provided by the Act .

The Bonds bear interest initially at the Dutch Auction Rate, as defined in the Indenture, hereinafter described, subject to change as provided in such Indenture. The Bonds will be subject to optional and mandatory redemption prior to maturity at the times, in the manner and upon the terms set forth in each of the Bonds. From such examination of the proceedings of the Fiscal Court of the County referred to above and from an examination of the Act, we are of the opinion that the County is duly authorized and empowered to issue the Bonds under the laws of the Commonwealth of Kentucky now in force.

We have examined an executed counterpart of a certain Loan Agreement, dated as of May 1, 2000 (the "Loan Agreement"), between the County and the Company and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Loan Agreement, pursuant to which the County has agreed to issue the Bonds and to lend the proceeds thereof to the Company to provide funds to pay and discharge, with other funds provided by the Company, the Prior Bonds and the Company has agreed to make Loan payments to the Trustee at times and in amounts fully adequate to pay maturing principal of, interest on and redemption premium, if any, on the Bonds as same become due and payable. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Loan Agreement; that the Loan Agreement has been duly authorized, executed and delivered by the County; and that the Loan Agreement is a legal, valid and binding obligation of the County, enforceable in accordance with its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

We have also examined an executed counterpart of a certain Indenture of Trust, dated as of May 1, 2000 (the "Indenture"), by and between the County and The Bank of New York, New York, New York, as trustee (the "Trustee"), securing the Bonds and setting forth the covenants and undertakings of the County in connection with the Bonds and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Indenture. Pursuant to the Indenture, certain of the County's rights under the Loan Agreement, including the right to receive payments thereunder, and all moneys and securities held by the Trustee in accordance with the Indenture (except moneys and securities in the Rebate Fund created thereby) have been assigned to the Trustee, as security for the holders of the Bonds. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Indenture; that the Indenture has been duly authorized, executed and delivered by the County; and that the Indenture is a legal, valid and binding obligation upon the parties thereto according to its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

In our opinion the Bonds have been validly authorized, executed and issued in accordance with the laws of the Commonwealth of Kentucky now in full force and effect, and constitute legal, valid and binding special obligations of the County entitled to the benefit of the security provided by the Indenture and enforceable in accordance with their terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought. The Bonds are payable by the County solely and only from payments and other amounts derived from the Loan Agreement and as provided in the Indenture.

In our opinion, under existing laws, including current statutes, regulations, administrative rulings and official interpretations by the Internal Revenue Service, subject to the exceptions and qualifications contained in the succeeding paragraph, interest on the Bonds is excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion is expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person," as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on the Bonds is an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. In arriving at this opinion, we have relied upon representations, factual statements and certifications of the Company with respect to certain material facts which are solely within the Company's knowledge in reaching our conclusion, inter alia, that all of the proceeds of the Prior Bonds were used to finance solid waste disposal facilities qualified for financing under Section 142(a)(6) of the Internal Revenue Code of 1986, as amended. Further, in arriving at the opinion set forth in this paragraph as to the exclusion from gross income of interest on the Bonds, we have assumed and this opinion is conditioned on, the payment and discharge of the Prior Bonds on or before the 90th day from the date of issuance of the Bonds, and the accuracy of and continuing compliance by the Company and the County with representations and covenants set forth in the Loan Agreement and the Indenture which are intended to assure compliance with certain tax-exempt interest provisions of the Code. Such representations and covenants must be accurate and must be complied with subsequent to the issuance of the Bonds in order that interest on the Bonds be excluded from gross income for federal income tax purposes. Failure to comply with certain of such representations and covenants in respect of the Bonds subsequent to the issuance of the Bonds could cause the interest thereon to be included in gross income for federal income tax purposes retroactively to the date of issuance of the Bonds. We express no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents with the approval of bond counsel (other than this firm) is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the 2000 Bonds upon a Determination of Taxability. We are further of the opinion that interest on the Bonds is excluded from gross income of the recipients thereof for Kentucky income tax purposes and that the Bonds are exempt from ad valorem taxation by the Commonwealth of Kentucky and all political subdivisions thereof.

Our opinion as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds is subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, we express no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Holders of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that, for taxable years beginning after December 31, 1986, property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income.

We have received opinions of John R. McCall, Esq., General Counsel of the Company and Gardner, Carton & Douglas, Chicago, Illinois, counsel to the Company, of even date herewith. In rendering this opinion, we have relied upon said opinions with respect to the matters therein. We have also received an opinion of even date herewith of Hon. Douglas Greenburg, County Attorney of the County, and relied upon said opinion with respect to the matters therein. Said opinions are in forms satisfactory to us as to both scope and content.

We express no opinion as to the title to, the description of, or the existence or priority of any liens, charges or encumbrances on, the Project.

In rendering the foregoing opinions, we are passing upon only those matters specifically set forth in such opinions and are not passing upon the investment quality of the Bonds or the accuracy or completeness of any statements made in connection with any sale thereof. The opinions herein are expressed as of the date hereof and we assume no obligation to supplement or update such opinions to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We are members of the Bar of the Commonwealth of Kentucky and do not purport to be experts on the laws of any jurisdiction other than the Commonwealth of Kentucky and the United States of America, and we express no opinion as to the laws of any jurisdiction other than those specified.

HARPER, FERGUSON & DAVIS

By: Spencer E. Harper, Jr.
SPENCER E. HARPER, JR.

APPENDIX B-2

(Form of Reoffering Opinion of Bond Counsel)

December 17, 2008

County of Mercer, Kentucky
Harrodsburg, Kentucky 40330

The Bank of New York Mellon,
as Trustee
West Paterson, New Jersey 07424

Re: Reoffering of $12,900,000 "County of Mercer, Kentucky, Solid Waste Disposal Facility Revenue Bonds, 2000 Series A (Kentucky Utilities Company Project)"

Ladies and Gentlemen:

This opinion is being furnished in accordance with the requirements of the Indenture of Trust, dated as of May 1, 2000 (the "Indenture"), between the County of Mercer, Kentucky (the "Issuer") and The Bank of New York Mellon, as Trustee (the "Trustee"), pertaining to $12,900,000 principal amount of County of Mercer, Kentucky, Solid Waste Disposal Facility Revenue Bonds, 2000 Series A (Kentucky Utilities Company Project), dated May 19, 2000 (the "Bonds"), in order to satisfy certain requirements of the Indenture. Pursuant to the authority of the Indenture and an ordinance adopted by the Issuer, the Company is terminating a municipal bond insurance policy insuring the Bonds and simultaneously delivering a letter of credit to the Trustee for the benefit of the Bondholders. The terms used herein denoted by initial capitals and not otherwise defined shall have the meanings specified in the Indenture.

We have examined the law and such documents and matters as we have deemed necessary to provide this opinion. As to questions of fact material to the opinions expressed herein, we have relied upon the provisions of the Indenture and related documents, and upon representations made to us without undertaking to verify the same by independent investigation.

Based upon the foregoing, as of the date hereof, we are of the opinion that the delivery of a letter of credit and the reoffering of the Bonds as described herein (a) is authorized or permitted by the Act and the Indenture and (b) will not adversely affect the validity of the Bonds or any exclusion from gross income for federal income tax purposes to which interest on the Bonds would otherwise be entitled. Interest on the Bonds is not and will not be excluded from gross income during any period when the Bonds are held by the Company or a "related person" of the Company as defined in Section 147(a) of the Internal Revenue Code of 1986, as amended.

In rendering this opinion, we assume, without verifying, that the Issuer and the Company have complied and will comply with all covenants contained in the Indenture, the Loan Agreement between the Issuer and the Company, dated May 1, 2000, and other documents relating to the Bonds. We rendered our approving opinion at the time of the issuance of the Bonds relating to, among other things, the validity of the Bonds and the exclusion from federal income taxation of interest on the Bonds. We have not been requested to update or continue such opinion and have not undertaken to do so. Accordingly, we do not express any opinion with respect to the Bonds except as set forth above.

Our opinion represents our legal judgment based upon our review of the law and the facts that we deem relevant to render such opinion and is not a guarantee of a result. This opinion is given as of the date hereof and we assume no obligation to review or supplement this opinion to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We express no opinion herein as to the investment quality of the Bonds or the adequacy, accuracy or completeness of any information furnished to any person in connection with any offer or sale of the Bonds.

Respectfully submitted,

STOLL KEENON OGDEN PLLC

Appendix C

[DELETED AND REPLACED – SEE APPENDIX C TO SUPPLEMENT DATED MAY 2, 2011]

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(q)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

Annual report to shareholders, or members, and statistical supplements covering the two (2) most recent years from the utility's application filing date.

Response:

There are no annual reports to shareholders or members during the period referenced. KU does not publish a statistical supplement.

Federal securities rules generally require the delivery of annual reports to public shareholders when requesting their vote via certain proxy solicitations. During the period in question, the common stock of KU has been wholly-owned by LG&E and KU Energy LLC, which is a wholly-owned subsidiary of PPL Corporation.

(Copies of the audited annual financial statements and other financial information of KU relating to the period described are provided in Filing Requirement 807 KAR 5:001 Section 10(6)(s), [Tab No. 38].)

Kentucky Utilities Company
Case No. 2012-00221
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(r)
Sponsoring Witness: Valerie L. Scott

Description of Filing Requirement:

The monthly managerial reports providing financial results of operations for the twelve (12) months in the test period.

Response:

See attached.

KENTUCKY UTILITIES COMPANY

Financial Reports

March 31, 2012

Index
Financial and Operating Reports

Kentucky Utilities Company
March 31, 2012

Certain reclassification entries have been made to the prior financial statements to conform to the current presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows, unless otherwise noted.

KENTUCKY UTILITIES COMPANY
Comparative Statement of Income
March 31, 2012

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 116,107,878.31	$ 125,112,688.39	$ (9,004,810.08)	(7.20)
Rate Refunds	-	-	-	-
Total Operating Revenues	116,107,878.31	125,112,688.39	(9,004,810.08)	(7.20)
Fuel for Electric Generation	36,924,018.07	40,175,198.87	(3,251,180.80)	(8.09)
Power Purchased	9,451,423.62	10,835,473.30	(1,384,049.68)	(12.77)
Other Operation Expenses	20,527,928.31	19,646,609.72	881,318.59	4.49
Maintenance	14,662,860.84	9,011,227.72	5,651,633.12	62.72
Depreciation	15,670,414.61	15,118,209.33	552,205.28	3.65
Amortization Expense	659,650.99	575,411.07	84,239.92	14.64
Regulatory Credits	(522,893.81)	(470,659.95)	(52,233.86)	(11.10)
Taxes				
Federal Income	(19,817,795.50)	(14,948,374.58)	(4,869,420.92)	(32.57)
State Income	(2,776,604.49)	(725,025.12)	(2,051,579.37)	(282.97)
Deferred Federal Income - Net	23,246,598.38	22,131,677.28	1,114,921.10	5.04
Deferred State Income - Net	2,899,852.11	1,776,808.83	1,123,043.28	63.21
Property and Other	2,596,391.74	2,164,646.30	431,745.44	19.95
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	(886.52)	(3,293.39)	2,406.87	73.08
Accretion Expense	262,355.28	226,528.85	35,826.43	15.82
Total Operating Expenses	103,783,313.63	105,514,438.23	(1,731,124.60)	(1.64)
Net Operating Income	12,324,564.68	19,598,250.16	(7,273,685.48)	(37.11)
Other Income Less Deductions				
Amortization of Investment Tax Credit	233,341.74	233,343.00	(1.26)	(0.00)
Other Income Less Deductions	354,174.03	1,729.59	352,444.44	20,377.34
AFUDC - Equity	3,347.88	1,809.68	1,538.20	85.00
Total Other Income Less Deductions	590,863.65	236,882.27	353,981.38	149.43
Income Before Interest Charges	12,915,428.33	19,835,132.43	(6,919,704.10)	(34.89)
Interest on Long-Term Debt	5,084,068.89	5,129,050.90	(44,982.01)	(0.88)
Amortization of Debt Expense - Net	305,857.64	291,476.03	14,381.61	4.93
Other Interest Expenses	433,445.39	524,543.60	(91,098.21)	(17.37)
AFUDC - Borrowed Funds	(866.43)	(549.45)	(316.98)	(57.69)
Total Interest Charges	5,822,505.49	5,944,521.08	(122,015.59)	(2.05)
Net Income	$ 7,092,922.84	$ 13,890,611.35	$ (6,797,688.51)	(48.94)

April 26, 2012

KENTUCKY UTILITIES COMPANY
Comparative Statement of Income
March 31, 2012

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 379,944,192.71	$ 405,425,221.70	$ (25,481,028.99)	(6.29)
Rate Refunds	-	-	-	-
Total Operating Revenues	379,944,192.71	405,425,221.70	(25,481,028.99)	(6.29)
Fuel for Electric Generation	125,413,071.09	131,244,357.03	(5,831,285.94)	(4.44)
Power Purchased	28,285,722.36	33,571,400.29	(5,285,677.93)	(15.74)
Other Operation Expenses	57,801,035.82	57,300,643.12	500,392.70	0.87
Maintenance	34,762,088.19	24,859,777.10	9,902,311.09	39.83
Depreciation	46,942,425.45	44,181,620.01	2,760,805.44	6.25
Amortization Expense	1,954,666.52	1,712,961.49	241,705.03	14.11
Regulatory Credits	(1,565,339.41)	(1,409,124.92)	(156,214.49)	(11.09)
Taxes				
Federal Income	(3,217,751.55)	7,088,549.80	(10,306,301.35)	(145.39)
State Income	251,123.89	2,806,983.86	(2,555,859.97)	(91.05)
Deferred Federal Income - Net	23,354,872.39	22,131,675.83	1,223,196.56	5.53
Deferred State Income - Net	2,899,852.12	1,776,808.83	1,123,043.29	63.21
Property and Other	7,767,478.88	6,739,170.85	1,028,308.03	15.26
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	(886.52)	(3,293.39)	2,406.87	73.08
Accretion Expense	783,723.30	676,731.51	106,991.79	15.81
Total Operating Expenses	325,432,082.53	332,678,261.41	(7,246,178.88)	(2.18)
Net Operating Income	54,512,110.18	72,746,960.29	(18,234,850.11)	(25.07)
Other Income Less Deductions				
Amortization of Investment Tax Credit	700,027.74	586,318.00	113,709.74	19.39
Other Income Less Deductions	(458,618.09)	757,526.02	(1,216,144.11)	(160.54)
AFUDC - Equity	9,395.38	4,931.90	4,463.48	90.50
Total Other Income Less Deductions	250,805.03	1,348,775.92	(1,097,970.89)	(81.41)
Income Before Interest Charges	54,762,915.21	74,095,736.21	(19,332,821.00)	(26.09)
Interest on Long-Term Debt	15,214,466.29	15,378,682.59	(164,216.30)	(1.07)
Amortization of Debt Expense - Net	917,572.92	871,840.42	45,732.50	5.25
Other Interest Expenses	1,162,938.33	1,433,339.17	(270,400.84)	(18.87)
AFUDC - Borrowed Funds	(2,432.58)	(1,495.57)	(937.01)	(62.65)
Total Interest Charges	17,292,544.96	17,682,366.61	(389,821.65)	(2.20)
Net Income	$ 37,470,370.25	$ 56,413,369.60	$ (18,942,999.35)	(33.58)

April 26, 2012

KENTUCKY UTILITIES COMPANY
Comparative Statement of Income
March 31, 2012

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues......................................	$ 1,522,035,957.11	$ 1,537,241,985.68	$ (15,206,028.57)	(0.99)
Rate Refunds...	-	355,385.29	(355,385.29)	(100.00)
Total Operating Revenues......................................	1,522,035,957.11	1,537,597,370.97	(15,561,413.86)	(1.01)
Fuel for Electric Generation......................................	516,817,356.17	501,144,494.77	15,672,861.40	3.13
Power Purchased...	103,829,269.81	154,190,992.53	(50,361,722.72)	(32.66)
Other Operation Expenses..	234,009,083.64	223,494,400.63	10,514,683.01	4.70
Maintenance..	126,205,679.78	109,746,892.71	16,458,787.07	15.00
Depreciation..	184,687,593.56	151,138,300.72	33,549,292.84	22.20
Amortization Expense...	7,505,149.44	6,594,409.48	910,739.96	13.81
Regulatory Credits..	(6,011,854.42)	(5,940,201.18)	(71,653.24)	(1.21)
Taxes				
Federal Income...	(17,247,753.46)	53,938,279.20	(71,186,032.66)	(131.98)
State Income...	1,899,319.18	13,031,186.26	(11,131,867.08)	(85.42)
Deferred Federal Income - Net...............................	102,811,975.59	37,796,519.12	65,015,456.47	172.01
Deferred State Income - Net...................................	11,097,503.08	3,780,387.88	7,317,115.20	193.55
Property and Other...	29,144,074.49	21,337,850.46	7,806,224.03	36.58
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances...........	(886.52)	(16,020.32)	15,133.80	94.47
Accretion Expense..	2,934,108.65	3,631,503.93	(697,395.28)	(19.20)
Total Operating Expenses......................................	1,297,680,618.99	1,273,868,996.19	23,811,622.80	1.87
Net Operating Income...	224,355,338.12	263,728,374.78	(39,373,036.66)	(14.93)
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	2,800,110.74	639,643.00	2,160,467.74	337.76
Other Income Less Deductions...........................	533,585.57	(471,889.30)	1,005,474.87	213.07
AFUDC - Equity...	47,125.06	562,455.71	(515,330.65)	(91.62)
Total Other Income Less Deductions......................	3,380,821.37	730,209.41	2,650,611.96	362.99
Income Before Interest Charges.............................	227,736,159.49	264,458,584.19	(36,722,424.70)	(13.89)
Interest on Long-Term Debt......................................	61,076,334.12	70,677,065.64	(9,600,731.52)	(13.58)
Amortization of Debt Expense - Net.........................	3,773,938.89	1,855,595.95	1,918,342.94	103.38
Other Interest Expenses..	5,107,381.64	4,496,292.04	611,089.60	13.59
AFUDC - Borrowed Funds.......................................	(13,892.09)	(731,782.42)	717,890.33	98.10
Total Interest Charges..	69,943,762.56	76,297,171.21	(6,353,408.65)	(8.33)
Net Income..	$ 157,792,396.93	$ 188,161,412.98	$ (30,369,016.05)	(16.14)

April 26, 2012

KENTUCKY UTILITIES COMPANY
Analysis of Retained Earnings
March 31, 2012

	Current Month		Year to Date		Year Ended Current Month	
Retained Earnings and Undistributed Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period..	$ 1,498,432,698.51	$ 14,964,134.75	$ 1,490,663,791.10	$ 16,355,594.75	$ 1,463,485,376.42	$ 15,711,982.75
Add:						
Net Income for Period...	7,092,922.84	-	37,470,370.25	-	157,792,396.93	-
Deduct:						
Common Dividends						
Common Stock Without Par Value	-	-	(24,000,000.00)	-	(116,500,000.00)	-
EE Inc..	495,596.00	(495,596.00)	1,887,056.00	(1,887,056.00)	1,243,444.00	(1,243,444.00)
Balance at End of Period..	$ 1,506,021,217.35	$ 14,468,538.75	$ 1,506,021,217.35	$ 14,468,538.75	$ 1,506,021,217.35	$ 14,468,538.75
Deferred Taxes Related to Undistributed Subsidiary Earnings		-		-		-
Balance of Undistributed Subsidiary Earnings.............................		14,468,538.75		14,468,538.75		14,468,538.75
Statutory Tax Rate..		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.......................................		$ 5,628,261.57		$ 5,628,261.57		$ 5,628,261.57

April 26, 2012

KENTUCKY UTILITIES COMPANY
Comparative Balance Sheets as of March 31, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,837,808,460.84	$ 6,535,226,485.12
Less: Reserves for Depreciation and Amortization	2,419,286,203.27	2,294,097,036.00
Total	4,418,522,257.57	4,241,129,449.12
Investments		
Electric Energy, Inc	6,465,195.55	12,916,180.55
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	179,120.94	179,120.94
Total	6,894,316.49	13,345,301.49
Current and Accrued Assets		
Cash	26,696,148.67	32,533,420.42
Special Deposits	-	511,450.27
Temporary Cash Investments	19,049,263.40	24,006,082.89
Accounts Receivable-Less Reserve	153,471,798.55	158,822,646.61
Accounts Receivable from Associated Companies	3,237,051.00	2,399.89
Materials and Supplies-At Average Cost		
Fuel	86,500,323.28	90,317,258.09
Plant Materials and Operating Supplies	34,275,059.84	33,292,754.47
Stores Expense	10,207,802.39	9,353,557.63
Emission Allowances	415,494.53	540,133.80
Prepayments	5,995,929.86	7,705,071.01
Miscellaneous Current and Accrued Assets	886.52	144,469.29
Total	339,849,758.04	357,229,244.37
Deferred Debits and Other		
Unamortized Debt Expense	20,993,395.72	20,951,061.01
Unamortized Loss on Bonds	11,623,874.20	12,228,846.88
Accumulated Deferred Income Taxes	85,241,359.67	95,312,656.15
Deferred Regulatory Assets	267,700,866.01	278,343,042.90
Other Deferred Debits	45,907,397.34	43,065,248.51
Total	431,466,892.94	449,900,855.45
Total Assets	$ 5,196,733,225.04	$ 5,061,604,850.43

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	315,858,083.00	315,858,083.00
Other Comprehensive Income	(5,681,776.49)	(2,499,968.95)
Retained Earnings	1,506,021,217.35	1,463,485,376.42
Unappropriated Undistributed Subsidiary Earnings	14,468,538.75	15,711,982.75
Total Proprietary Capital	2,138,484,751.30	2,100,374,161.91
Pollution Control Bonds	350,779,405.00	350,779,405.00
First Mortgage Bonds	1,489,970,968.75	1,489,335,718.75
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,840,750,373.75	1,840,115,123.75
Total Capitalization	3,979,235,125.05	3,940,489,285.66
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Accounts Payable	89,650,512.28	76,815,641.10
Accounts Payable to Associated Companies	35,561,724.97	38,226,572.22
Customer Deposits	23,057,677.96	22,823,008.76
Taxes Accrued	15,423,195.66	23,861,888.47
Interest Accrued	26,028,639.20	23,475,407.19
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	20,585,090.84	20,152,328.40
Total	210,306,840.91	205,354,846.14
Deferred Credits and Other		
Accumulated Deferred Income Taxes	581,925,806.57	482,369,779.76
Investment Tax Credit	100,707,740.58	103,507,851.32
Regulatory Liabilities	108,999,483.67	117,393,178.49
Customer Advances for Construction	3,147,887.16	2,874,868.44
Asset Retirement Obligations	62,573,225.51	54,658,037.92
Other Deferred Credits	12,482,364.45	16,560,938.25
Miscellaneous Long-Term Liabilities	2,630,529.78	2,390,659.63
Accum Provision for Postretirement Benefits	134,724,221.36	136,005,404.82
Total	1,007,191,259.08	915,760,718.63
Total Liabilities and Stockholders Equity	$ 5,196,733,225.04	$ 5,061,604,850.43

April 26, 2012

KENTUCKY UTILITIES COMPANY
Statement of Capitalization and Short-Term Debt
March 31, 2012

	Authorized Shares	Issued and Outstanding Shares	Issued and Outstanding Amount	Percent of Total Capital
Proprietary Capital				
Common Stock - Without Par..	80,000,000	37,817,878	$ 308,139,977.56	
Less: Common Stock Expense..			321,288.87	
Paid-In Capital..			315,858,083.00	
Other Comprehensive Income..			(5,681,776.49)	
Retained Earnings..			1,506,021,217.35	
Unappropriated Undistributed Subsidiary Earnings.............			14,468,538.75	
Total Proprietary Capital..			2,138,484,751.30	53.74
Long-Term Debt				
Pollution Control Bonds				
Mercer County 2000 Series A due 05/01/23 Var%...........			12,900,000.00	
Carroll County 2002 Series A due 02/01/32 Var%...........			20,930,000.00	
Carroll County 2002 Series B due 02/01/32 Var%...........			2,400,000.00	
Carroll County 2002 Series C due 10/01/32 Var%...........			96,000,000.00	
Mercer County 2002 Series A due 02/01/32 Var%...........			7,400,000.00	
Muhlenburg County 2002 Series A due 02/01/32 Var%...			2,400,000.00	
Carroll County 2004 Series A due 10/01/34 Var%...........			50,000,000.00	
Carroll County 2006 Series B due 10/01/34 Var%...........			54,000,000.00	
Carroll County 2007 Series A due 02/01/26 5.75%..........			17,875,000.00	
Trimble County 2007 Series A due 03/01/37 6.00%.........			8,927,000.00	
Carroll County 2008 Series A due 02/01/32 Var%...........			77,947,405.00	
Total Pollution Control Bonds..			350,779,405.00	8.82
First Mortgage Bonds				
First Mortgage Bond due 11/01/15 1.625%........................			250,000,000.00	
First Mortgage Bond due 11/01/20 3.250%.......................			500,000,000.00	
First Mortgage Bond due 11/01/40 5.125%.......................			750,000,000.00	
Total First Mortgage Bonds..			1,500,000,000.00	37.69
Less: First Mortgage Bonds Debt Discount				
First Mortgage Bond due 11/01/15 1.625%........................			(634,375.03)	
First Mortgage Bond due 11/01/20 3.250%.......................			(1,630,125.00)	
First Mortgage Bond due 11/01/40 5.125%.......................			(7,764,531.22)	
			(10,029,031.25)	(0.25)
Total First Mortgage Bonds - Net of Debt Discount............			1,489,970,968.75	37.44
Total Capitalization..			$ 3,979,235,125.05	100.00

April 26, 2012

KENTUCKY UTILITIES COMPANY
Summary Trial Balance
March 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 6,837,808,460.84	$ 6,837,808,460.84
Reserves for Depreciation and Amortization		(2,419,286,203.27)
Depreciation of Plant	(2,400,219,948.85)	
Amortization of Plant	(19,066,254.42)	
Investments		6,894,316.49
Electric Energy, Inc	6,465,195.55	
Ohio Valley Electric Corporation	250,000.00	
Nonutility Property Reserve	179,120.94	
Cash	26,696,148.67	26,696,148.67
Temporary Cash Investments	19,049,263.40	19,049,263.40
Accounts Receivable - Less Reserve		153,471,798.55
Customers - Active	75,321,597.70	
Unbilled Revenues	67,598,169.04	
Income Tax Receivable - Federal	3,191,330.70	
IMPA	2,015,683.56	
IMEA	1,897,065.62	
Income Tax Receivable - State	1,177,805.90	
Transmission Sales	963,631.96	
Damage Claims	203,638.04	
Sundry Accounts Receivable	25,371.22	
Bechtel Liquidated Damages	25,110.00	
Other	3,233,801.27	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	1,498,397.14	
Reserve	(2,126,581.00)	
Accrual	(1,131,628.77)	
Recoveries	(367,317.58)	
A/R Miscellaneous	(28,544.12)	
LEM Reserve	(25,732.13)	
Accounts Receivable from Associated Companies		3,237,051.00
LG&E and KU Services/Louisville Gas and Electric Company	3,237,051.00	
Fuel		86,500,323.28
Coal 1,406,025.14 Tons @ $56.30 MMBtu 31,650,854.98 @ 250.09¢	79,156,728.73	
Fuel Oil 2,907,284 Gallons @ 251.46¢	7,310,689.88	
Gas Pipeline 12,743.31 Mcf @ $2.58	32,904.67	
Plant Materials and Operating Supplies		34,275,059.84
Regular Materials and Supplies	33,242,127.67	
Limestone 109,837.62 Tons @ $9.40	1,032,932.13	
Other Reagents	0.04	
Stores Expense Undistributed	10,207,802.39	10,207,802.39

April 26, 2012

Kentucky Utilities Company
Summary Trial Balance
March 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Emission Allowances	$ 415,494.53	$ 415,494.53
Prepayments		5,995,929.86
Insurance	1,622,924.89	
Lease	555,273.22	
Taxes	504,338.61	
Risk Management and Workers Compensation	75,000.00	
Other	3,238,393.14	
Miscellaneous Current Assets		886.52
Miscellaneous Current Assets	886.52	
Unamortized Debt Expense		20,993,395.72
Carroll County 2002 Series A due 02/01/32 Var%	81,318.34	
Carroll County 2002 Series B due 02/01/32 Var%	56,515.62	
Carroll County 2002 Series C due 10/01/32 Var%	1,509,988.83	
Mercer County 2002 Series A due 02/01/32 Var%	22,703.40	
Muhlenburg County 2002 Series A due 02/01/32 Var%	62,912.11	
Carroll County 2006 Series B due 10/01/34 Var%	1,078,200.72	
Carroll County 2007 Series A due 02/01/26 5.75%	461,232.72	
Trimble County 2007 Series A due 03/01/37 6.00%	400,452.61	
Carroll County 2008 Series A due 02/01/32 Var%	682,260.17	
First Mortgage Bond due 11/01/15 1.625%	1,665,768.95	
First Mortgage Bond due 11/01/20 3.250%	3,604,914.27	
First Mortgage Bond due 11/01/40 5.125%	7,144,838.89	
Revolving Credit Agreement	4,222,289.09	
Unamortized Loss on Bonds		11,623,874.20
Refinanced and Called Bonds	11,623,874.20	
Accumulated Deferred Income Taxes		85,241,359.67
Federal	72,026,646.48	
State	13,214,713.19	
Regulatory Assets		267,700,866.01
Pension and Postretirement Benefits	111,399,554.00	
ASC 740 - Deferred Taxes	74,777,990.70	
2009 Winter Storm	47,697,298.82	
Asset Retirement Obligations	8,986,939.02	
FERC Jurisdictional Pension Expense	6,073,527.36	
Virginia Mountain Snowstorm	5,538,197.62	
VA Fuel Component Non-Current	4,552,000.00	
MISO Exit Fee	3,312,042.63	
2008 Wind Storm	1,829,596.95	
Fuel Adjustment Clause	1,150,000.00	
Rate Case Expenses	925,298.60	
EKPC FERC Transmission Cost	641,502.72	
KCCS Funding	537,810.30	
General Management Audit	142,520.69	
CMRG Funding	136,586.60	
Other Deferred Debits	45,907,397.34	45,907,397.34
Total Assets	$ 5,196,733,225.04	$ 5,196,733,225.04

April 26, 2012

KENTUCKY UTILITIES COMPANY
Summary Trial Balance
March 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 2,138,484,751.30
Common Stock	308,139,977.56	
Less: Common Stock Expense	321,288.87	
Paid-In Capital	315,858,083.00	
Other Comprehensive Income	(5,681,776.49)	
Retained Earnings	1,506,021,217.35	
Unappropriated Undistributed Subsidiary Earnings	14,468,538.75	
Bonds		1,840,750,373.75
First Mortgage Bonds	1,489,970,968.75	
Pollution Control Bonds - Net of Reacquired Bonds	350,779,405.00	
Accounts Payable		89,650,512.28
Regular	87,910,143.64	
Salaries and Wages Accrued	1,631,917.77	
Employee Withholdings Payable	108,450.87	
Accounts Payable to Associated Companies		35,561,724.97
LG&E and KU Services/Louisville Gas and Electric Company	35,561,724.97	
Customers' Deposits	23,057,677.96	23,057,677.96
Taxes Accrued	15,423,195.66	15,423,195.66
Interest Accrued		26,028,639.20
Mercer County 2000 Series A due 05/01/23 Var%	1,624.84	
Carroll County 2002 Series A due 02/01/32 Var%	5,404.06	
Carroll County 2002 Series B due 02/01/32 Var%	527.87	
Carroll County 2002 Series C due 10/01/32 Var%	2,368.00	
Mercer County 2002 Series A due 02/01/32 Var%	1,627.60	
Muhlenburg County 2002 Series A due 02/01/32 Var%	527.87	
Carroll County 2004 Series A due 10/01/34 Var%	6,571.04	
Carroll County 2006 Series B due 10/01/34 Var%	7,037.70	
Carroll County 2007 Series A due 02/01/26 5.75%	342,604.17	
Trimble County 2007 Series A due 03/01/37 6.00%	178,540.00	
Carroll County 2008 Series A due 02/01/32 Var%	10,222.61	
First Mortgage Bond due 11/01/15 1.625%	1,692,708.33	
First Mortgage Bond due 11/01/20 3.250%	6,770,833.33	
First Mortgage Bond due 11/01/40 5.125%	16,015,625.00	
Customers' Deposits	919,863.09	
Interest Accrued on Tax Liabilities	66,563.00	
Other	5,990.69	

April 26, 2012

Kentucky Utilities Company
Summary Trial Balance
March 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Miscellaneous Current and Accrued Liabilities		$ 20,585,090.84
Vacation Pay Accrued	6,643,905.88	
Franchise Fee Payable	5,450,684.68	
Customer Overpayments	4,050,003.66	
Tax Collections Payable	3,944,889.94	
Home Energy Assistance	456,185.17	
Other	39,421.51	
Accumulated Deferred Income Taxes		581,925,806.57
Federal	507,288,713.14	
State	74,637,093.43	
Investment Tax Credit		100,707,740.58
Advanced Coal Credit	97,952,444.26	
Job Development Credit	2,755,296.32	
Regulatory Liabilities		108,999,483.67
Deferred Taxes		
Federal	62,274,987.61	
State	19,580,115.61	
Postretirement Benefits	9,291,186.00	
Environmental Cost Recovery	9,227,608.15	
Asset Retirement Obligations	3,538,293.96	
Spare Parts	2,160,772.21	
DSM Cost Recovery	1,812,012.77	
MISO Schedule 10 Charges	1,114,507.36	
Customers' Advances for Construction		3,147,887.16
Line Extensions	2,929,087.69	
Other	218,799.47	
Asset Retirement Obligations	62,573,225.51	62,573,225.51
Other Deferred Credits	12,482,364.45	12,482,364.45
Miscellaneous Long-Term Liabilities		2,630,529.78
Workers' Compensation	2,630,529.78	
Accumulated Provision for Benefits		134,724,221.36
Pension Payable	68,832,302.39	
Postretirement Benefits - ASC 715	66,145,738.97	
Post Employment Benefits Payable	6,658,395.00	
Post Employment Medicare Subsidy	(364,214.00)	
Medicare Subsidy - ASC 715	(6,548,001.00)	
Total Liabilities and Stockholders Equity	$ 5,196,733,225.04	$ 5,196,733,225.04

April 26, 2012

KENTUCKY UTILITIES COMPANY
Statement of Cash Flows
March 31, 2012

	Year to Date	
	2012	2011
Cash Flows from Operating Activities		
Net income	$ 37,470,370.25	$ 56,413,369.60
Items not requiring (providing) cash currently:		
Depreciation	46,942,425.45	44,181,620.01
Amortization	1,954,666.52	1,712,961.49
Deferred income taxes - net	23,950,952.65	24,978,780.04
Investment tax credit - net	(682,252.74)	(604,091.00)
Gain on disposal of assets	(4,058.49)	9,652.44
Other	4,246,326.80	(3,929,372.29)
Change in receivables	8,991,939.72	51,602,964.77
Change in inventory	9,713,185.71	3,350,100.65
Change in allowance inventory	34,967.79	26,445.20
Change in payables and accrued expenses	31,244,363.44	2,720,059.15
Change in regulatory assets	826,960.89	(63,404,281.33)
Change in regulatory liabilities	761,896.70	62,280,548.09
Change in other deferred debits	(1,307,658.80)	(5,625,267.94)
Change in other deferred credits	5,821,614.08	8,275,052.73
Pension and postretirement funding	(16,983,700.00)	(44,096,800.00)
Other	(2,440,524.61)	5,226,645.95
Less: Allowance for other funds used during construction	(6,962.80)	(4,931.90)
Less: Undistributed earnings of subsidiary company	1,887,056.00	(1,279,587.00)
Net cash provided (used) by operating activities	152,421,568.56	141,833,868.66
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(111,426,722.14)	(44,406,312.53)
Less: Allowance for other funds used during construction	6,962.80	4,931.90
Proceeds received from sales of property	(292,691.35)	(9,652.44)
Change in derivatives	-	(2,801.63)
Change in restricted cash	45,500.00	(285,761.02)
Other	(2,149,020.71)	(2,195,013.45)
Net cash provided (used) by investing activities	(113,815,971.40)	(46,894,609.17)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	-	(299,203.04)
Net change in short-term debt	-	(10,434,000.00)
Dividends on common stock	(24,000,000.00)	(31,000,000.00)
Net cash provided (used) by financing activities	(24,000,000.00)	(41,733,203.04)
Net Increase (Decrease) in Cash and Cash Equivalents	14,605,597.16	53,206,056.45
Cash and Cash Equivalents at Beginning of Period	31,139,814.91	3,333,446.86
Cash and Cash Equivalents at End of Period	$ 45,745,412.07	$ 56,539,503.31

April 26, 2012

KENTUCKY UTILITIES COMPANY
Analysis of Interest Charges
March 31, 2012

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Interest on Long-Term Debt						
Loan Agreement - Pollution Control Bonds						
Mercer County 2000 Series A due 05/01/23 Var%..............	$ 1,624.84	$ 2,763.78	$ 4,035.65	$ 8,390.30	$ 19,921.68	$ 42,117.54
Carroll County 2002 Series A due 02/01/32 Var%..............	6,204.66	17,546.80	20,157.99	43,259.17	150,526.09	146,877.03
Carroll County 2002 Series B due 02/01/32 Var%..............	711.48	1,989.04	2,422.95	5,008.24	16,905.20	16,889.88
Carroll County 2002 Series C due 10/01/32 Var%..............	22,672.00	30,352.00	39,781.34	87,040.00	207,152.10	511,152.00
Mercer County 2002 Series A due 02/01/32 Var%..............	2,193.72	5,321.92	7,470.78	14,293.15	52,093.79	50,928.22
Muhlenburg County 2002 Series A due 02/01/32 Var%.......	711.48	1,726.03	2,422.95	4,635.62	16,895.31	16,517.26
Carroll County 2004 Series A due 10/01/34 Var%..............	6,571.04	11,753.42	16,297.83	37,616.44	81,941.60	157,630.14
Carroll County 2006 Series B due 10/01/34 Var%..............	7,037.70	13,048.77	17,749.17	41,439.45	89,147.52	170,092.60
Carroll County 2007 Series A due 02/01/26 5.75%.............	85,651.04	85,651.04	256,953.13	256,953.12	1,027,812.51	1,027,812.49
Trimble County 2007 Series A due 03/01/37 6.00%............	44,635.00	44,635.00	133,905.00	133,905.00	535,620.00	535,620.00
Carroll County 2008 Series A due 02/01/32 Var%..............	10,222.61	18,429.76	25,769.50	58,642.08	128,318.36	244,413.16
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/01/15 1.625%.........................	338,541.66	338,541.67	1,015,625.00	1,015,625.01	4,062,499.98	1,523,437.52
First Mortgage Bond due 11/01/20 3.250%.........................	1,354,166.66	1,354,166.67	4,062,500.00	4,062,500.01	16,249,999.98	6,093,750.02
First Mortgage Bond due 11/01/40 5.125%.........................	3,203,125.00	3,203,125.00	9,609,375.00	9,609,375.00	38,437,500.00	14,414,062.50
Fidelia/PPL..	-	-	-	-	-	45,725,765.28
Total..	5,084,068.89	5,129,050.90	15,214,466.29	15,378,682.59	61,076,334.12	70,677,065.64
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense..................................	255,443.25	241,061.64	766,329.75	720,597.25	3,168,966.21	1,250,684.55
Amortization of Loss on Reacquired Debt...............................	50,414.39	50,414.39	151,243.17	151,243.17	604,972.68	604,911.40
Total..	305,857.64	291,476.03	917,572.92	871,840.42	3,773,938.89	1,855,595.95
Other Interest Charges						
Customers' Deposits..	111,902.51	110,557.01	328,563.51	319,130.60	1,373,105.57	1,300,429.27
Other Tax Deficiencies...	67,194.00	5,544.00	67,194.00	(84,914.00)	170,466.75	2,155.07
Interest on DSM Cost Recovery...	(558.36)	(4,009.18)	(11,395.79)	(1,501.88)	1,801.12	7,066.48
Interest on Debt to Associated Companies..............................	-	970.73	1,181.62	3,926.90	3,576.07	107,135.83
AFUDC Borrowed Funds..	(866.43)	(549.45)	(2,432.58)	(1,495.57)	(13,892.09)	(731,782.42)
Other Interest Expense..	254,907.24	411,481.04	777,394.99	1,196,697.55	3,558,432.13	3,079,505.39
Total..	432,578.96	523,994.15	1,160,505.75	1,431,843.60	5,093,489.55	3,764,509.62
Total Interest..	$ 5,822,505.49	$ 5,944,521.08	$ 17,292,544.96	$ 17,682,366.61	$ 69,943,762.56	$ 76,297,171.21

April 26, 2012

KENTUCKY UTILITIES COMPANY
Analysis of Taxes Charged and Accrued
March 31, 2012

Kind of Taxes	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year
Taxes Charged to Accounts 408.1 and 409.1...........				
Property Taxes..	$ 1,740,788.00	$ 1,494,264.00	$ 5,222,364.00	$ 4,482,792.00
Unemployment..	9,683.48	8,934.09	134,192.67	70,722.79
FICA...	671,503.83	499,036.55	1,882,176.35	1,692,075.25
Public Service Commission Fee..............................	168,112.85	157,659.37	504,338.55	472,978.11
Federal Income..	(19,817,795.50)	(14,948,374.58)	(3,217,751.55)	7,088,549.80
State Income..	(2,776,604.49)	(725,025.12)	251,123.89	2,806,983.86
Miscellaneous..	6,303.58	4,752.29	24,407.31	20,602.70
Total Charged to Operating Expense..........	(19,998,008.25)	(13,508,753.40)	4,800,851.22	16,634,704.51
Taxes Charged to Other Accounts..........................	4,991,671.36	(433,098.84)	196,090.96	1,520,425.70
Taxes Accrued on Intercompany Accounts............	(38,592.27)	(360,904.58)	(114,689.50)	(1,241,227.66)
Total Taxes Charged.................................	$ (15,044,929.16)	$ (14,302,756.82)	$ 4,882,252.68	$ 16,913,902.55

Analysis of Taxes Accrued - Account 236

Kind of Taxes	Taxes Accrued At Beginning Of Year	Accruals To Date This Year	Payments To Date This Year	Taxes Accrued At End Of Month
Property Taxes..	$ 9,493,201.72	$ 5,222,865.00	$ 283,284.64	$ 14,432,782.08
Unemployment..	70,966.44	114,825.95	21,840.56	163,951.83
FICA...	554,166.20	1,547,494.43	1,907,987.72	193,672.91
Federal Income..	0.00	(3,237,051.00)	(3,237,051.00)	-
State Income..	0.00	0.00	0.00	-
Kentucky Sales and Use Tax..................................	587,236.42	1,244,985.61	1,212,933.09	619,288.94
Miscellaneous..	24,367.21	(10,867.31)	0.00	13,499.90
Totals..	$ 10,729,937.99	$ 4,882,252.68	$ 188,995.01	$ 15,423,195.66

April 26, 2012

KENTUCKY UTILITIES COMPANY
Summary of Utility Plant
March 31, 2012

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant in Service**						
Electric						
Electric Distribution	$ 1,382,494,206.57	$ 23,690,004.54	$ (1,877,123.91)	$ (79.97)	$ 21,812,800.66	$ 1,404,307,007.23
Electric General Plant	129,755,046.33	7,437,252.08	-	(454,977.96)	6,982,274.12	136,737,320.45
Electric Hydro Production	17,134,240.66	7,762.58	(322.65)	-	7,439.93	17,141,680.59
Electric Intangible Plant	54,860,528.56	479,546.42	(635,176.41)	-	(155,629.99)	54,704,898.57
Electric Other Production	525,899,447.50	8,136,610.38	(1,765,489.48)	-	6,371,120.90	532,270,568.40
Electric Steam Production	2,659,096,509.86	520,778,066.84	(16,026,275.41)	-	504,751,791.43	3,163,848,301.29
Electric Transmission	574,848,507.91	14,943,313.47	(1,971,978.96)	(3,798.94)	12,967,535.57	587,816,043.48
Total 101 Accounts	5,344,088,487.39	575,472,556.31	(22,276,366.82)	(458,856.87)	552,737,332.62	5,896,825,820.01
102 **Electric Plant Purchased or Sold**						
Electric						
Electric General Plant	-	-	-	73,177.16	73,177.16	73,177.16
Electric Steam	483,341.17	-	-	-	-	483,341.17
Total 102001	483,341.17	-	-	73,177.16	73,177.16	556,518.33
105 **Plant Held for Future Use**						
Electric						
Electric Distribution	792,599.21	-	-	-	-	792,599.21
Electric Steam	-	-	-	-	-	-
Total 105001	792,599.21	-	-	-	-	792,599.21
106 **Completed Construction Not Classified**						
Electric						
Electric Distribution	23,980,094.26	5,472,555.16	-	-	5,472,555.16	29,452,649.42
Electric General Plant	7,738,634.34	(4,454,580.39)	-	-	(4,454,580.39)	3,284,053.95
Electric Hydro Production	11,505,517.08	109,272.33	-	-	109,272.33	11,614,789.41
Electric Intangible Plant	3,788,766.16	1,710,468.35	-	-	1,710,468.35	5,499,234.51
Electric Other Production	1,093,637.80	18,938.78	-	-	18,938.78	1,112,576.58
Electric Steam Production	967,980,441.51	(504,678,601.28)	-	-	(504,678,601.28)	463,301,840.23
Electric Transmission	82,036,721.90	(1,906,781.03)	-	-	(1,906,781.03)	80,129,940.87
Total 106 Accounts	1,098,123,813.05	(503,728,728.08)	-	-	(503,728,728.08)	594,395,084.97
121 **Nonutility Property**						
Common						
Non Utility Property	179,120.94	-	-	-	-	179,120.94
Total 121001	179,120.94	-	-	-	-	179,120.94
107 **Construction Work In Progress**						
Electric						
Electric	339,711,431.64	5,527,006.68	-	-	5,527,006.68	345,238,438.32
Total 107001	339,711,431.64	5,527,006.68	-	-	5,527,006.68	345,238,438.32
Total Plant (Non-CWIP)	6,443,667,361.76	71,743,828.23	(22,276,366.82)	(385,679.71)	49,081,781.70	6,492,749,143.46
Total Plant + CWIP	6,783,378,793.40	77,270,834.91	(22,276,366.82)	(385,679.71)	54,608,788.38	6,837,987,581.78
Total Plant + CWIP - Nonutility (BS)	$ 6,783,199,672.46	$ 77,270,834.91	$ (22,276,366.82)	$ (385,679.71)	$ 54,608,788.38	$ 6,837,808,460.84

April 26, 2012

KENTUCKY UTILITIES COMPANY
Summary of Utility Plant - Reserve for Depreciation of Utility Plant
March 31, 2012

	Beginning Balance	Accruals	Retirements	Transfers/ Adjustments	ARO Settlements	RWIP Transfers Out	Cost of Removal	Salvage	Other Credits	Ending Balance
Life Reserve										
Electric Distribution....................................	$ (411,056,321.05)	$ (7,141,164.13)	$ 1,877,123.91	$ -	$ -	$ -	$ -	$ -	$ -	$ (416,320,361.27)
Electric Distribution - ARO.........................	(6,765.54)	(7,577.61)	-	(307.57)	-	-	-	-	-	(14,650.72)
Electric General Plant.................................	(54,490,775.21)	(1,743,510.49)	-	362,131.50	-	-	-	-	-	(55,872,154.20)
Electric Hydro Production...........................	(7,872,943.76)	(50,855.07)	322.65	-	-	-	-	-	-	(7,923,476.18)
Electric Hydro Production - ARO................	(1,094.53)	(243.24)	-	-	-	-	-	-	-	(1,337.77)
Electric Other Production............................	(175,058,471.14)	(4,245,748.04)	1,765,489.48	-	-	-	-	-	-	(177,538,729.70)
Electric Other Production - ARO.................	(763.60)	(169.71)	-	-	-	-	-	-	-	(933.31)
Electric Steam Production............................	(1,146,202,987.01)	(22,963,405.14)	16,026,275.41	-	-	-	-	-	-	(1,153,140,116.74)
Electric Steam Production - ARO................	(3,512,619.50)	(769,536.04)	-	-	-	-	-	-	-	(4,282,155.54)
Electric Transmission..................................	(217,974,783.91)	(2,422,619.16)	1,971,978.96	2,327.24	-	-	-	-	-	(218,423,096.87)
Electric Transmission - ARO.......................	(2,671.85)	(4,089.51)	-	-	-	-	-	-	-	(6,761.36)
Non Utility Property....................................	-	-	-	-	-	-	-	-	-	-
	(2,016,180,197.10)	(39,348,918.14)	21,641,190.41	364,151.17	-	-	-	-	-	(2,033,523,773.66)
Cost of Removal										
Electric Distribution....................................	(199,658,860.39)	(2,104,246.17)	-	-	-	-	1,761,492.76	-	-	(200,001,613.80)
Electric General Plant.................................	250,582.68	(14,590.52)	-	(276,148.86)	-	-	-	-	-	(40,156.70)
Electric Hydro Production...........................	(350,001.10)	(1,327.42)	-	-	-	-	1,776.48	-	-	(349,552.04)
Electric Other Production............................	(3,572,221.61)	(227,608.31)	-	-	-	-	466,414.71	-	-	(3,333,415.21)
Electric Steam Production............................	(136,295,560.94)	(6,527,387.31)	-	(58,702.47)	-	-	4,686,590.65	-	-	(138,195,060.07)
Electric Transmission..................................	(138,104,734.27)	(735,215.83)	-	540.02	-	-	1,328,277.85	-	-	(137,511,132.23)
Non Utility Property....................................	-	-	-	-	-	-	-	-	-	-
	(477,730,795.63)	(9,610,375.56)	-	(334,311.31)	-	-	8,244,552.45	-	-	(479,430,930.05)
Salvage										
Electric Distribution....................................	49,559,394.32	514,202.91	-	-	-	-	-	(312,565.06)	-	49,761,032.17
Electric General Plant.................................	137,079.64	-	-	-	-	-	-	-	-	137,079.64
Electric Hydro Production...........................	46,518.69	-	-	-	-	-	-	-	-	46,518.69
Electric Other Production............................	618,891.61	-	-	-	-	-	-	-	-	618,891.61
Electric Steam Production............................	24,235,511.41	1,228,695.98	-	-	-	-	-	(172,783.20)	-	25,291,424.19
Electric Transmission..................................	23,638,002.34	170,653.66	-	-	-	-	-	(38,262.47)	-	23,770,393.53
Non Utility Property....................................	-	-	-	-	-	-	-	-	-	-
	98,235,398.01	1,913,552.55	-	-	-	-	-	(523,610.73)	-	99,625,339.83
Total Reserves										
Electric Distribution....................................	(561,155,787.12)	(8,731,207.39)	1,877,123.91	-	-	-	1,761,492.76	(312,565.06)	-	(566,560,942.90)
Electric Distribution - ARO.........................	(6,765.54)	(7,577.61)	-	(307.57)	-	-	-	-	-	(14,650.72)
Electric General Plant.................................	(54,103,112.89)	(1,758,101.01)	-	85,982.64	-	-	-	-	-	(55,775,231.26)
Electric Hydro Production...........................	(8,176,426.17)	(52,182.49)	322.65	-	-	-	1,776.48	-	-	(8,226,509.53)
Electric Hydro Production - ARO................	(1,094.53)	(243.24)	-	-	-	-	-	-	-	(1,337.77)
Electric Other Production............................	(178,011,801.14)	(4,473,356.35)	1,765,489.48	-	-	-	466,414.71	-	-	(180,253,253.30)
Electric Other Production - ARO.................	(763.60)	(169.71)	-	-	-	-	-	-	-	(933.31)
Electric Steam Production............................	(1,258,263,036.54)	(28,262,096.47)	16,026,275.41	(58,702.47)	-	-	4,686,590.65	(172,783.20)	-	(1,266,043,752.62)
Electric Steam Production - ARO................	(3,512,619.50)	(769,536.04)	-	-	-	-	-	-	-	(4,282,155.54)
Electric Transmission..................................	(332,441,515.84)	(2,987,181.33)	1,971,978.96	2,867.26	-	-	1,328,277.85	(38,262.47)	-	(332,163,835.57)
Electric Transmission - ARO.......................	(2,671.85)	(4,089.51)	-	-	-	-	-	-	-	(6,761.36)
Non Utility Property....................................	-	-	-	-	-	-	-	-	-	-
	(2,395,675,594.72)	(47,045,741.15)	21,641,190.41	29,839.86	-	-	8,244,552.45	(523,610.73)	-	(2,413,329,363.88)
Retirement Work in Process										
Electric..	18,384,586.20	-	-	296,749.84	-	(7,720,941.72)	2,783,248.53	(118,661.58)	(515,566.24)	13,109,415.03
	18,384,586.20	-	-	296,749.84	-	(7,720,941.72)	2,783,248.53	(118,661.58)	(515,566.24)	13,109,415.03
YTD ACTIVITY	(2,377,291,008.52)	(47,045,741.15)	21,641,190.41	326,589.70	-	(7,720,941.72)	11,027,800.98	(642,272.31)	(515,566.24)	(2,400,219,948.85)
Amortization										
Electric..	(17,746,764.31)	(1,954,666.52)	635,176.41	-	-	-	-	-	-	(19,066,254.42)
	(17,746,764.31)	(1,954,666.52)	635,176.41	-	-	-	-	-	-	(19,066,254.42)
Depreciation & Amortization Total										
Depreciation & Amortization Total...............	(2,395,037,772.83)	(49,000,407.67)	22,276,366.82	326,589.70	-	(7,720,941.72)	11,027,800.98	(642,272.31)	(515,566.24)	(2,419,286,203.27)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)...............	$ 4,388,161,899.63									$ 4,418,522,257.57

April 26, 2012

KENTUCKY UTILITIES COMPANY
Statement of Income with Purchase Accounting
As of March 31, 2012

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 116,107,878.31	$ -	$ 116,107,878.31
Rate Refunds	-	-	-
Total Operating Revenues	116,107,878.31	-	116,107,878.31
Fuel for Electric Generation	36,924,018.07	-	36,924,018.07
Power Purchased	9,451,423.62	-	9,451,423.62
Other Operation Expenses	20,527,928.31	-	20,527,928.31
Maintenance	14,662,860.84	-	14,662,860.84
Depreciation	15,670,414.61	-	15,670,414.61
Amortization Expense	659,650.99	-	659,650.99
Regulatory Credits	(522,893.81)	-	(522,893.81)
Taxes			
Federal Income	(19,817,795.50)	-	(19,817,795.50)
State Income	(2,776,604.49)	-	(2,776,604.49)
Deferred Federal Income - Net	23,246,598.38	50,404.84	23,297,003.22
Deferred State Income - Net	2,899,852.11	9,192.37	2,909,044.48
Property and Other	2,596,391.74	-	2,596,391.74
Loss (Gain) from Disposition of Allowances	(886.52)	-	(886.52)
Accretion Expense	262,355.28	-	262,355.28
Total Operating Expenses	103,783,313.63	59,597.21	103,842,910.84
Net Operating Income	12,324,564.68	(59,597.21)	12,264,967.47
Other Income Less Deductions			
Amortization of Investment Tax Credit	233,341.74	-	233,341.74
Other Income Less Deductions	354,174.03	12,331.35	366,505.38
AFUDC - Equity	3,347.88	-	3,347.88
Total Other Income Less Deductions	590,863.65	12,331.35	603,195.00
Income Before Interest Charges	12,915,428.33	(47,265.86)	12,868,162.47
Interest on Long-Term Debt	5,084,068.89	(5,525.49)	5,078,543.40
Amortization of Debt Expense - Net	305,857.64	-	305,857.64
Other Interest Expenses	433,445.39	-	433,445.39
AFUDC - Borrowed Funds	(866.43)	-	(866.43)
Total Interest Charges	5,822,505.49	(5,525.49)	5,816,980.00
Net Income	$ 7,092,922.84	$ (41,740.37)	$ 7,051,182.47

April 26, 2012

KENTUCKY UTILITIES COMPANY
Statement of Income with Purchase Accounting
As of March 31, 2012

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues....................................	$ 379,944,192.71	$ -	$ 379,944,192.71
Rate Refunds..	-	-	-
Total Operating Revenues....................................	379,944,192.71	-	379,944,192.71
Fuel for Electric Generation......................................	125,413,071.09	-	125,413,071.09
Power Purchased..	28,285,722.36	-	28,285,722.36
Other Operation Expenses..	57,801,035.82	-	57,801,035.82
Maintenance...	34,762,088.19	-	34,762,088.19
Depreciation...	46,942,425.45	-	46,942,425.45
Amortization Expense..	1,954,666.52	-	1,954,666.52
Regulatory Credits..	(1,565,339.41)	-	(1,565,339.41)
Taxes			
Federal Income...	(3,217,751.55)	-	(3,217,751.55)
State Income...	251,123.89	-	251,123.89
Deferred Federal Income - Net..............................	23,354,872.39	5,453.66	23,360,326.05
Deferred State Income - Net..................................	2,899,852.12	994.59	2,900,846.71
Property and Other..	7,767,478.88	-	7,767,478.88
Loss (Gain) from Disposition of Allowances...........	(886.52)	-	(886.52)
Accretion Expense..	783,723.30	-	783,723.30
Total Operating Expenses.....................................	325,432,082.53	6,448.25	325,438,530.78
Net Operating Income...	54,512,110.18	(6,448.25)	54,505,661.93
Other Income Less Deductions			
Amortization of Investment Tax Credit.............	700,027.74	-	700,027.74
Other Income Less Deductions..........................	(458,618.09)	(135,349.35)	(593,967.44)
AFUDC - Equity...	9,395.38	-	9,395.38
Total Other Income Less Deductions....................	250,805.03	(135,349.35)	115,455.68
Income Before Interest Charges............................	54,762,915.21	(141,797.60)	54,621,117.61
Interest on Long-Term Debt....................................	15,214,466.29	(16,576.47)	15,197,889.82
Amortization of Debt Expense - Net........................	917,572.92	-	917,572.92
Other Interest Expenses...	1,162,938.33	-	1,162,938.33
AFUDC - Borrowed Funds......................................	(2,432.58)	-	(2,432.58)
Total Interest Charges...	17,292,544.96	(16,576.47)	17,275,968.49
Net Income..	$ 37,470,370.25	$ (125,221.13)	$ 37,345,149.12

April 26, 2012

KENTUCKY UTILITIES COMPANY
Analysis of Retained Earnings with Purchase Accounting
As of March 31, 2012

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,498,432,698.51	$ 14,964,134.75	$ (1,402,302,487.43)	$ (15,422,265.34)	$ 96,130,211.08	$ (458,130.59)
Add						
Net Income for Period...	7,092,922.84	-	(41,740.37)	-	7,051,182.47	-
Deductions:						
Common Dividends						
Common Stock Without Par Value..................	-	-	-	-	-	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc..	495,596.00	(495,596.00)	73,840.35	(73,840.35)	569,436.35	(569,436.35)
Balance at End of Period	$ 1,506,021,217.35	$ 14,468,538.75	$ (1,402,270,387.45)	$ (15,496,105.69)	$ 103,750,829.90	$ (1,027,566.94)
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings................		14,468,538.75		(15,496,105.69)		(1,027,566.94)
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.........................		$ 5,628,261.57		$ (6,027,985.11)		$ (399,723.54)

April 26, 2012

KENTUCKY UTILITIES COMPANY
Analysis of Retained Earnings with Purchase Accounting
As of March 31, 2012

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,490,663,791.10	$ 16,355,594.75	$ (1,402,366,687.37)	$ (15,274,584.64)	$ 88,297,103.73	$ 1,081,010.11
Add						
Net Income for Period ………………………………	37,470,370.25	-	(125,221.13)	-	37,345,149.12	-
Deductions:						
Common Dividends						
Common Stock Without Par Value....................	(24,000,000.00)	-	-	-	(24,000,000.00)	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc……………………….…………	1,887,056.00	(1,887,056.00)	221,521.05	(221,521.05)	2,108,577.05	(2,108,577.05)
Balance at End of Period …...……………………………	$ 1,506,021,217.35	$ 14,468,538.75	$ (1,402,270,387.45)	$ (15,496,105.69)	$ 103,750,829.90	$ (1,027,566.94)
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings…………		14,468,538.75		(15,496,105.69)		(1,027,566.94)
Statutory Tax Rate…...…………………………………		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary…...………………		$ 5,628,261.57		$ (6,027,985.11)		$ (399,723.54)

April 26, 2012

KENTUCKY UTILITIES COMPANY
Analysis of Retained Earnings with Purchase Accounting
As of March 31, 2012

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,463,485,376.42	$ 15,711,982.75	$ (1,402,655,522.06)	$ (14,610,021.49)	$ 60,829,854.36	$ 1,101,961.26
Add						
Net Income for Period...	157,792,396.93	-	(500,949.59)	-	157,291,447.34	-
Deductions:						
Common Dividends						
Common Stock Without Par Value...................	(116,500,000.00)	-	-	-	(116,500,000.00)	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	1,243,444.00	(1,243,444.00)	886,084.20	(886,084.20)	2,129,528.20	(2,129,528.20)
Balance at End of Period	$ 1,506,021,217.35	$ 14,468,538.75	$ (1,402,270,387.45)	$ (15,496,105.69)	$ 103,750,829.90	$ (1,027,566.94)
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings................		14,468,538.75		(15,496,105.69)		(1,027,566.94)
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary..........................		$ 5,628,261.57		$ (6,027,985.11)		$ (399,723.54)

Combined Balance of Retained Earnings	12 MONTHS 3/31/2012	12 MONTHS 3/31/2011
Retained Earnings at Beginning of Period.......................	$ 61,931,815.62	$ 1,372,035,946.19
Net Income for Period	157,291,447.34	189,220,256.03
FIN 48 Adjustment...	-	-
Subtotal..	219,223,262.96	1,561,256,202.22
Deduct		
Purchase Accounting Adjustment...............................	-	1,418,324,386.60
Dividends on Common Stock.....................................	116,500,000.00	81,000,000.00
Retained Earnings at End of Period.................................	$ 102,723,262.96	$ 61,931,815.62

April 26, 2012

KENTUCKY UTILITIES COMPANY
Balance Sheet with Purchase Accounting
As of March 31, 2012

Assets	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 6,837,808,460.84	$ -	$ 6,837,808,460.84
Less Reserves for Depreciation and Amortization.....	2,419,286,203.27	-	2,419,286,203.27
Total..	4,418,522,257.57	-	4,418,522,257.57
Investments			
Electric Energy, Inc...	6,465,195.55	16,466,397.06	22,931,592.61
Ohio Valley Electric Corporation.............................	250,000.00	-	250,000.00
Nonutility Property - Less Reserve...........................	179,120.94	-	179,120.94
Special Funds...	-	-	-
Total..	6,894,316.49	16,466,397.06	23,360,713.55
Current and Accrued Assets			
Cash..	26,696,148.67	-	26,696,148.67
Special Deposits..	-	-	-
Temporary Cash Investments.................................	19,049,263.40	-	19,049,263.40
Accounts Receivable-Less Reserve........................	153,471,798.55	-	153,471,798.55
Accounts Receivable from Assoc Companies..........	3,237,051.00	-	3,237,051.00
Materials & Supplies-At Average Cost			
Fuel..	86,500,323.28	-	86,500,323.28
Plant Materials & Operating Supplies..................	34,275,059.84	-	34,275,059.84
Stores Expense..	10,207,802.39	-	10,207,802.39
Allowance Inventory..	415,494.53	-	415,494.53
Prepayments..	5,995,929.86	-	5,995,929.86
Miscellaneous Current & Accrued Assets..............	886.52	-	886.52
Total..	339,849,758.04	-	339,849,758.04
Deferred Debits and Other			
Unamortized Debt Expense......................................	20,993,395.72	(4,355,584.52)	16,637,811.20
Unamortized Loss on Bonds....................................	11,623,874.20	-	11,623,874.20
Accumulated Deferred Income Taxes.......................	85,241,359.67	54,683,768.41	139,925,128.08
Deferred Regulatory Assets.....................................	267,700,866.01	10,132,915.47	277,833,781.48
Other Deferred Debits..	45,907,397.34	133,730,387.54	179,637,784.88
Goodwill..	-	607,404,368.23	607,404,368.23
Total..	431,466,892.94	801,595,855.13	1,233,062,748.07
Total Assets..	$ 5,196,733,225.04	$ 818,062,252.19	$ 6,014,795,477.23

April 26, 2012

KENTUCKY UTILITIES COMPANY
Balance Sheet with Purchase Accounting
As of March 31, 2012

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Proprietary Capital			
Common Stock..	$ 308,139,977.56	$ -	$ 308,139,977.56
Less: Common Stock Expense.....................................	321,288.87	-	321,288.87
Paid-In Capital..	315,858,083.00	2,032,588,750.94	2,348,446,833.94
Other Comprehensive Income.....................................	(5,681,776.49)	1,990,823.26	(3,690,953.23)
Retained Earnings..	1,506,021,217.35	(1,402,270,387.45)	103,750,829.90
Unappropriated Undistributed Subsidiary Earnings....	14,468,538.75	(15,496,105.69)	(1,027,566.94)
Total Proprietary Capital..	2,138,484,751.30	616,813,081.06	2,755,297,832.36
Pollution Control Bonds - Net of Reacquired Bonds...	350,779,405.00	1,067,521.66	351,846,926.66
First Mortgage Bonds..	1,489,970,968.75	-	1,489,970,968.75
Total Long-Term Debt...	1,840,750,373.75	1,067,521.66	1,841,817,895.41
Total Capitalization..	3,979,235,125.05	617,880,602.72	4,597,115,727.77
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Accounts Payable...	89,650,512.28	-	89,650,512.28
Accounts Payable to Associated Companies................	35,561,724.97	-	35,561,724.97
Customer Deposits...	23,057,677.96	-	23,057,677.96
Taxes Accrued...	15,423,195.66	-	15,423,195.66
Interest Accrued...	26,028,639.20	-	26,028,639.20
Dividends Declared..	-	-	-
Miscellaneous Current and Accrued Liabilities...........	20,585,090.84	-	20,585,090.84
Total..	210,306,840.91	-	210,306,840.91
Deferred Credits and Other			
Accumulated Deferred Income Taxes..........................	581,925,806.57	60,673,930.98	642,599,737.55
Investment Tax Credit..	100,707,740.58	-	100,707,740.58
Regulatory Liabilities...	108,999,483.67	133,730,387.54	242,729,871.21
Customer Advances for Construction..........................	3,147,887.16	-	3,147,887.16
Asset Retirement Obligations......................................	62,573,225.51	-	62,573,225.51
Other Deferred Credits...	12,482,364.45	5,777,330.95	18,259,695.40
Miscellaneous Long-Term Liabilities..........................	2,630,529.78	-	2,630,529.78
Accum Provision for Postretirement Benefits.............	134,724,221.36	-	134,724,221.36
Total..	1,007,191,259.08	200,181,649.47	1,207,372,908.55
Total Liabilities and Stockholders' Equity.........................	$ 5,196,733,225.04	$ 818,062,252.19	$ 6,014,795,477.23

April 26, 2012

KENTUCKY UTILITIES COMPANY

Financial Reports

February 29, 2012

Index
Financial and Operating Reports

Kentucky Utilities Company
February 29, 2012

Certain reclassification entries have been made to the prior financial statements to conform to the current presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows, unless otherwise noted.

Kentucky Utilities Company
Comparative Statement of Income
February 29, 2012

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues.....................................	$ 126,307,013.69	$ 127,079,879.16	$ (772,865.47)	(0.61)
Rate Refunds..	-	-	-	-
Total Operating Revenues......................................	126,307,013.69	127,079,879.16	(772,865.47)	(0.61)
Fuel for Electric Generation......................................	42,542,492.15	41,333,833.61	1,208,658.54	2.92
Power Purchased...	7,976,655.49	8,851,790.22	(875,134.73)	(9.89)
Other Operation Expenses..	18,005,230.02	19,172,693.40	(1,167,463.38)	(6.09)
Maintenance..	12,373,627.51	8,448,621.65	3,925,005.86	46.46
Depreciation..	15,657,769.81	15,096,502.99	561,266.82	3.72
Amortization Expense...	650,767.69	573,285.82	77,481.87	13.52
Regulatory Credits..	(523,417.91)	(469,706.90)	(53,711.01)	(11.44)
Taxes				
Federal Income...	6,931,480.08	8,477,003.58	(1,545,523.50)	(18.23)
State Income...	1,264,099.71	1,059,075.10	205,024.61	19.36
Deferred Federal Income - Net...............................	-	-	-	-
Deferred State Income - Net..................................	-	-	-	-
Property and Other...	2,575,900.37	2,284,890.39	291,009.98	12.74
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances...........	-	-	-	-
Accretion Expense..	261,239.52	225,575.83	35,663.69	15.81
Total Operating Expenses......................................	107,715,844.44	105,053,565.69	2,662,278.75	2.53
Net Operating Income...	18,591,169.25	22,026,313.47	(3,435,144.22)	(15.60)
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	233,343.00	233,343.00	-	-
Other Income Less Deductions...........................	(596,481.22)	899,842.93	(1,496,324.15)	(166.29)
AFUDC - Equity...	3,126.04	1,608.59	1,517.45	94.33
Total Other Income Less Deductions......................	(360,012.18)	1,134,794.52	(1,494,806.70)	(131.72)
Income Before Interest Charges.............................	18,231,157.07	23,161,107.99	(4,929,950.92)	(21.29)
Interest on Long-Term Debt......................................	5,071,252.67	5,125,596.58	(54,343.91)	(1.06)
Amortization of Debt Expense - Net.........................	305,857.64	291,167.61	14,690.03	5.05
Other Interest Expenses..	350,873.94	382,050.61	(31,176.67)	(8.16)
AFUDC - Borrowed Funds.......................................	(809.42)	(487.45)	(321.97)	(66.05)
Total Interest Charges..	5,727,174.83	5,798,327.35	(71,152.52)	(1.23)
Net Income..	$ 12,503,982.24	$ 17,362,780.64	$ (4,858,798.40)	(27.98)

March 21, 2012

Kentucky Utilities Company
Comparative Statement of Income
February 29, 2012

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues.....................................	$ 263,836,314.40	$ 280,312,533.31	$ (16,476,218.91)	(5.88)
Rate Refunds..	-	-	-	-
Total Operating Revenues......................................	263,836,314.40	280,312,533.31	(16,476,218.91)	(5.88)
Fuel for Electric Generation......................................	88,489,053.02	91,069,158.16	(2,580,105.14)	(2.83)
Power Purchased...	18,834,298.74	22,735,926.99	(3,901,628.25)	(17.16)
Other Operation Expenses..	37,273,107.51	37,654,033.40	(380,925.89)	(1.01)
Maintenance..	20,099,227.35	15,848,549.38	4,250,677.97	26.82
Depreciation..	31,272,010.84	29,063,410.68	2,208,600.16	7.60
Amortization Expense...	1,295,015.53	1,137,550.42	157,465.11	13.84
Regulatory Credits..	(1,042,445.60)	(938,464.97)	(103,980.63)	(11.08)
Taxes				
Federal Income...	16,600,043.95	22,036,924.38	(5,436,880.43)	(24.67)
State Income...	3,027,728.38	3,532,008.98	(504,280.60)	(14.28)
Deferred Federal Income - Net...............................	108,274.01	(1.45)	108,275.46	7,467,273.10
Deferred State Income - Net..................................	0.01	-	0.01	100.00
Property and Other...	5,171,087.14	4,574,524.55	596,562.59	13.04
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances...........	-	-	-	-
Accretion Expense..	521,368.02	450,202.66	71,165.36	15.81
Total Operating Expenses......................................	221,648,768.90	227,163,823.18	(5,515,054.28)	(2.43)
Net Operating Income...	42,187,545.50	53,148,710.13	(10,961,164.63)	(20.62)
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	466,686.00	352,975.00	113,711.00	32.22
Other Income Less Deductions...........................	(812,792.12)	755,796.43	(1,568,588.55)	(207.54)
AFUDC - Equity...	6,047.50	3,122.22	2,925.28	93.69
Total Other Income Less Deductions......................	(340,058.62)	1,111,893.65	(1,451,952.27)	(130.58)
Income Before Interest Charges.............................	41,847,486.88	54,260,603.78	(12,413,116.90)	(22.88)
Interest on Long-Term Debt......................................	10,130,397.40	10,249,631.69	(119,234.29)	(1.16)
Amortization of Debt Expense - Net.........................	611,715.28	580,364.39	31,350.89	5.40
Other Interest Expenses..	729,492.94	908,795.57	(179,302.63)	(19.73)
AFUDC - Borrowed Funds.......................................	(1,566.15)	(946.12)	(620.03)	(65.53)
Total Interest Charges..	11,470,039.47	11,737,845.53	(267,806.06)	(2.28)
Net Income..	$ 30,377,447.41	$ 42,522,758.25	$ (12,145,310.84)	(28.56)

March 21, 2012

Kentucky Utilities Company
Comparative Statement of Income
February 29, 2012

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues......................................	$ 1,531,040,767.19	$ 1,496,495,299.95	$ 34,545,467.24	2.31
Rate Refunds...	-	89,385.29	(89,385.29)	(100.00)
Total Operating Revenues.......................................	1,531,040,767.19	1,496,584,685.24	34,456,081.95	2.30
Fuel for Electric Generation......................................	520,068,536.97	494,363,304.79	25,705,232.18	5.20
Power Purchased...	105,213,319.49	160,951,036.56	(55,737,717.07)	(34.63)
Other Operation Expenses..	233,127,765.05	221,114,171.86	12,013,593.19	5.43
Maintenance..	120,554,046.66	109,551,670.72	11,002,375.94	10.04
Depreciation..	184,135,388.28	146,810,267.75	37,325,120.53	25.42
Amortization Expense...	7,420,909.52	6,577,942.46	842,967.06	12.82
Regulatory Credits..	(5,959,620.56)	(5,676,592.80)	(283,027.76)	(4.99)
Taxes				
Federal Income...	(12,378,332.54)	57,246,337.40	(69,624,669.94)	(121.62)
State Income...	3,950,898.55	11,516,421.97	(7,565,523.42)	(65.69)
Deferred Federal Income - Net...............................	101,697,054.49	22,559,132.20	79,137,922.29	350.80
Deferred State Income - Net...................................	9,974,459.80	3,311,038.18	6,663,421.62	201.25
Property and Other...	28,712,329.05	21,051,734.71	7,660,594.34	36.39
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances...........	(3,293.39)	(56,750.74)	53,457.35	94.20
Accretion Expense..	2,898,282.22	3,587,281.70	(688,999.48)	(19.21)
Total Operating Expenses......................................	1,299,411,743.59	1,252,906,996.76	46,504,746.83	3.71
Net Operating Income...	231,629,023.60	243,677,688.48	(12,048,664.88)	(4.94)
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	2,800,112.00	412,225.00	2,387,887.00	579.27
Other Income Less Deductions...........................	181,141.13	444,431.76	(263,290.63)	(59.24)
AFUDC - Equity...	45,586.86	548,544.60	(502,957.74)	(91.69)
Total Other Income Less Deductions......................	3,026,839.99	1,405,201.36	1,621,638.63	115.40
Income Before Interest Charges.............................	234,655,863.59	245,082,889.84	(10,427,026.25)	(4.25)
Interest on Long-Term Debt......................................	61,121,316.13	72,077,780.26	(10,956,464.13)	(15.20)
Amortization of Debt Expense - Net.........................	3,759,557.28	1,632,515.51	2,127,041.77	130.29
Other Interest Expenses..	5,198,479.85	4,118,697.95	1,079,781.90	26.22
AFUDC - Borrowed Funds.......................................	(13,575.11)	(811,429.48)	797,854.37	98.33
Total Interest Charges..	70,065,778.15	77,017,564.24	(6,951,786.09)	(9.03)
Net Income..	$ 164,590,085.44	$ 168,065,325.60	$ (3,475,240.16)	(2.07)

March 21, 2012

Kentucky Utilities Company
Analysis of Retained Earnings
February 29, 2012

Retained Earnings and Undistributed Earnings	Current Month Total Retained Earnings	Current Month Undistributed Subsidiary Earnings	Year to Date Total Retained Earnings	Year to Date Undistributed Subsidiary Earnings	Year Ended Current Month Total Retained Earnings	Year Ended Current Month Undistributed Subsidiary Earnings
Balance at Beginning of Period..	$ 1,508,988,854.27	$ 15,903,996.75	$ 1,490,663,791.10	$ 16,355,594.75	$ 1,449,554,889.07	$ 15,751,858.75
Add:						
Net Income for Period...	12,503,982.24	-	30,377,447.41	-	164,590,085.44	-
Deduct:						
Common Dividends						
Common Stock Without Par Value	(24,000,000.00)	-	(24,000,000.00)	-	(116,500,000.00)	-
EE Inc..	939,862.00	(939,862.00)	1,391,460.00	(1,391,460.00)	787,724.00	(787,724.00)
Balance at End of Period..	$ 1,498,432,698.51	$ 14,964,134.75	$ 1,498,432,698.51	$ 14,964,134.75	$ 1,498,432,698.51	$ 14,964,134.75
Deferred Taxes Related to Undistributed Subsidiary Earnings		-		-		-
Balance of Undistributed Subsidiary Earnings.............................		14,964,134.75		14,964,134.75		14,964,134.75
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.......................................		$ 5,821,048.42		$ 5,821,048.42		$ 5,821,048.42

March 21, 2012

Kentucky Utilities Company
Comparative Balance Sheets as of February 29, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,821,675,179.68	$ 6,511,673,964.80
Less: Reserves for Depreciation and Amortization	2,420,575,372.98	2,281,535,561.91
Total	4,401,099,806.70	4,230,138,402.89
Investments		
Electric Energy, Inc	6,914,711.55	12,950,174.55
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	179,120.94	179,120.94
Total	7,343,832.49	13,379,295.49
Current and Accrued Assets		
Cash	37,207,894.02	41,294,319.46
Special Deposits	-	138,750.37
Temporary Cash Investments	13,045,237.19	5,001,658.34
Accounts Receivable-Less Reserve	163,002,243.65	177,993,606.26
Accounts Receivable from Associated Companies	-	13,924.32
Materials and Supplies-At Average Cost		
Fuel	84,398,050.88	91,112,459.59
Plant Materials and Operating Supplies	34,371,771.07	32,666,760.22
Stores Expense	10,204,327.46	9,133,444.75
Emission Allowances	426,062.63	549,017.50
Prepayments	7,005,733.57	8,145,485.21
Miscellaneous Current and Accrued Assets	-	259,413.56
Total	349,661,320.47	366,308,839.58
Deferred Debits and Other		
Unamortized Debt Expense	21,195,901.47	21,107,592.06
Unamortized Loss on Bonds	11,674,288.59	12,279,261.27
Accumulated Deferred Income Taxes	86,638,419.05	98,973,011.75
Deferred Regulatory Assets	270,129,911.18	272,708,013.00
Other Deferred Debits	45,461,107.65	41,858,164.44
Total	435,099,627.94	446,926,042.52
Total Assets	$ 5,193,204,587.60	$ 5,056,752,580.48

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	315,858,083.00	315,858,083.00
Other Comprehensive Income	(5,692,006.25)	(2,501,273.97)
Retained Earnings	1,498,432,698.51	1,449,554,889.07
Unappropriated Undistributed Subsidiary Earnings	14,964,134.75	15,751,858.75
Total Proprietary Capital	2,131,381,598.70	2,086,482,245.54
Pollution Control Bonds	350,779,405.00	350,779,405.00
First Mortgage Bonds	1,489,918,031.25	1,489,282,781.25
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,840,697,436.25	1,840,062,186.25
Total Capitalization	3,972,079,034.95	3,926,544,431.79
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Accounts Payable	91,837,948.35	75,671,958.81
Accounts Payable to Associated Companies	28,944,224.53	20,968,382.51
Customer Deposits	23,087,288.98	23,029,190.40
Taxes Accrued	28,853,192.31	47,838,106.21
Interest Accrued	20,849,869.90	18,397,561.14
Dividends Declared	24,000,000.00	31,000,000.00
Miscellaneous Current and Accrued Liabilities	18,823,326.42	18,176,963.20
Total	236,395,850.49	235,082,162.27
Deferred Credits and Other		
Accumulated Deferred Income Taxes	557,374,045.20	460,742,213.58
Investment Tax Credit	100,941,082.32	103,741,194.32
Regulatory Liabilities	109,273,663.62	120,695,918.43
Customer Advances for Construction	3,145,247.98	2,864,865.13
Asset Retirement Obligations	62,310,870.23	54,431,509.07
Other Deferred Credits	13,197,873.84	14,215,758.56
Miscellaneous Long-Term Liabilities	2,695,347.71	2,429,122.51
Accum Provision for Postretirement Benefits	135,791,571.26	136,005,404.82
Total	984,729,702.16	895,125,986.42
Total Liabilities and Stockholders Equity	$ 5,193,204,587.60	$ 5,056,752,580.48

March 21, 2012

Kentucky Utilities Company
Statement of Capitalization and Short-Term Debt
February 29, 2012

	Authorized Shares	Issued and Outstanding Shares	Issued and Outstanding Amount	Percent of Total Capital
Proprietary Capital				
Common Stock - Without Par	80,000,000	37,817,878	$ 308,139,977.56	
Less: Common Stock Expense			321,288.87	
Paid-In Capital			315,858,083.00	
Other Comprehensive Income			(5,692,006.25)	
Retained Earnings			1,498,432,698.51	
Unappropriated Undistributed Subsidiary Earnings			14,964,134.75	
Total Proprietary Capital			2,131,381,598.70	53.66
Long-Term Debt				
Pollution Control Bonds				
Mercer County 2000 Series A due 05/01/23 Var%			12,900,000.00	
Carroll County 2002 Series A due 02/01/32 Var%			20,930,000.00	
Carroll County 2002 Series B due 02/01/32 Var%			2,400,000.00	
Carroll County 2002 Series C due 10/01/32 Var%			96,000,000.00	
Mercer County 2002 Series A due 02/01/32 Var%			7,400,000.00	
Muhlenburg County 2002 Series A due 02/01/32 Var%			2,400,000.00	
Carroll County 2004 Series A due 10/01/34 Var%			50,000,000.00	
Carroll County 2006 Series B due 10/01/34 Var%			54,000,000.00	
Carroll County 2007 Series A due 02/01/26 5.75%			17,875,000.00	
Trimble County 2007 Series A due 03/01/37 6.00%			8,927,000.00	
Carroll County 2008 Series A due 02/01/32 Var%			77,947,405.00	
Total Pollution Control Bonds			350,779,405.00	8.83
First Mortgage Bonds				
First Mortgage Bond due 11/01/15 1.625%			250,000,000.00	
First Mortgage Bond due 11/01/20 3.250%			500,000,000.00	
First Mortgage Bond due 11/01/40 5.125%			750,000,000.00	
Total First Mortgage Bonds			1,500,000,000.00	37.76
Less: First Mortgage Bonds Debt Discount				
First Mortgage Bond due 11/01/15 1.625%			(648,958.36)	
First Mortgage Bond due 11/01/20 3.250%			(1,645,875.00)	
First Mortgage Bond due 11/01/40 5.125%			(7,787,135.39)	
			(10,081,968.75)	(0.25)
Total First Mortgage Bonds - Net of Debt Discount			1,489,918,031.25	37.51
Total Capitalization			$ 3,972,079,034.95	100.00

March 21, 2012

Kentucky Utilities Company
Summary Trial Balance
February 29, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 6,821,675,179.68	$ 6,821,675,179.68
Reserves for Depreciation and Amortization		(2,420,575,372.98)
Depreciation of Plant	(2,401,533,593.14)	
Amortization of Plant	(19,041,779.84)	
Investments		7,343,832.49
Electric Energy, Inc	6,914,711.55	
Ohio Valley Electric Corporation	250,000.00	
Nonutility Property Reserve	179,120.94	
Cash	37,207,894.02	37,207,894.02
Temporary Cash Investments	13,045,237.19	13,045,237.19
Accounts Receivable - Less Reserve		163,002,243.65
Customers - Active	84,750,661.30	
Unbilled Revenues	72,848,373.41	
IMPA	1,506,410.66	
IMEA	1,416,701.07	
Transmission Sales	1,163,898.72	
Damage Claims	341,999.69	
Bechtel Liquidated Damages	48,600.00	
Sundry Accounts Receivable	23,463.77	
Other	3,117,245.79	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	1,174,190.36	
Reserve	(2,107,849.00)	
Accrual	(926,947.13)	
Recoveries	(247,243.23)	
A/R Miscellaneous	(81,529.63)	
LEM Reserve	(25,732.13)	
Fuel		84,398,050.88
Coal 1,327,610.70 Tons @ $57.74 MMBtu 30,050,068.91 @ 255.07¢	76,650,073.15	
Fuel Oil 3,036,063 Gallons @ 253.30¢	7,690,390.73	
Gas Pipeline 12,957.61 Mcf @ $4.44	57,587.00	
Plant Materials and Operating Supplies		34,371,771.07
Regular Materials and Supplies	33,447,935.91	
Limestone 96,146.56 Tons @ $9.61	923,835.13	
Other Reagents	0.03	
Stores Expense Undistributed	10,204,327.46	10,204,327.46

March 21, 2012

Kentucky Utilities Company
Summary Trial Balance
February 29, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Emission Allowances	$ 426,062.63	$ 426,062.63
Prepayments		7,005,733.57
Insurance	2,085,692.18	
Taxes	672,451.46	
Lease	568,186.56	
Risk Management and Workers Compensation	75,000.00	
Other	3,604,403.37	
Unamortized Debt Expense		21,195,901.47
Carroll County 2002 Series A due 02/01/32 Var%	81,660.34	
Carroll County 2002 Series B due 02/01/32 Var%	56,753.62	
Carroll County 2002 Series C due 10/01/32 Var%	1,516,127.00	
Mercer County 2002 Series A due 02/01/32 Var%	22,798.40	
Muhlenburg County 2002 Series A due 02/01/32 Var%	63,177.11	
Carroll County 2006 Series B due 10/01/34 Var%	1,082,194.06	
Carroll County 2007 Series A due 02/01/26 5.75%	464,011.23	
Trimble County 2007 Series A due 03/01/37 6.00%	401,791.92	
Carroll County 2008 Series A due 02/01/32 Var%	685,126.81	
First Mortgage Bond due 11/01/15 1.625%	1,704,196.13	
First Mortgage Bond due 11/01/20 3.250%	3,639,777.60	
First Mortgage Bond due 11/01/40 5.125%	7,165,642.31	
Revolving Credit Agreement	4,312,644.94	
Unamortized Loss on Bonds		11,674,288.59
Refinanced and Called Bonds	11,674,288.59	
Accumulated Deferred Income Taxes		86,638,419.05
Federal	73,166,692.83	
State	13,471,726.22	
Regulatory Assets		270,129,911.18
Pension and Postretirement Benefits	113,455,867.00	
ASC 740 - Deferred Taxes	75,212,354.54	
2009 Winter Storm	48,174,271.80	
Asset Retirement Obligations	8,464,045.21	
FERC Jurisdictional Pension Expense	6,009,166.26	
Virginia Mountain Snowstorm	5,638,892.12	
VA Fuel Component Non-Current	4,655,000.00	
MISO Exit Fee	3,424,638.13	
2008 Wind Storm	1,847,892.92	
Rate Case Expenses	952,727.29	
Fuel Adjustment Clause	781,000.00	
EKPC FERC Transmission Cost	669,394.14	
KCCS Funding	557,017.81	
CMRG Funding	145,123.27	
General Management Audit	142,520.69	
Other Deferred Debits	45,461,107.65	45,461,107.65
Total Assets	$ 5,193,204,587.60	$ 5,193,204,587.60

March 21, 2012

Kentucky Utilities Company
Summary Trial Balance
February 29, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 2,131,381,598.70
Common Stock	308,139,977.56	
Less: Common Stock Expense	321,288.87	
Paid-In Capital	315,858,083.00	
Other Comprehensive Income	(5,692,006.25)	
Retained Earnings	1,498,432,698.51	
Unappropriated Undistributed Subsidiary Earnings	14,964,134.75	
Bonds		1,840,697,436.25
First Mortgage Bonds	1,489,918,031.25	
Pollution Control Bonds - Net of Reacquired Bonds	350,779,405.00	
Accounts Payable		91,837,948.35
Regular	83,333,052.22	
Employee Withholdings Payable	4,701,688.95	
Salaries and Wages Accrued	3,803,207.18	
Accounts Payable to Associated Companies		28,944,224.53
LG&E and KU Services/Louisville Gas and Electric Company	28,944,224.53	
Customers' Deposits	23,087,288.98	23,087,288.98
Taxes Accrued	28,853,192.31	28,853,192.31
Interest Accrued		20,849,869.90
Mercer County 2000 Series A due 05/01/23 Var%	1,554.34	
Carroll County 2002 Series A due 02/01/32 Var%	8,606.46	
Carroll County 2002 Series B due 02/01/32 Var%	619.67	
Carroll County 2002 Series C due 10/01/32 Var%	6,016.00	
Mercer County 2002 Series A due 02/01/32 Var%	1,910.66	
Muhlenburg County 2002 Series A due 02/01/32 Var%	619.67	
Carroll County 2004 Series A due 10/01/34 Var%	6,325.14	
Carroll County 2006 Series B due 10/01/34 Var%	7,140.98	
Carroll County 2007 Series A due 02/01/26 5.75%	256,953.13	
Trimble County 2007 Series A due 03/01/37 6.00%	133,905.00	
Carroll County 2008 Series A due 02/01/32 Var%	10,329.10	
First Mortgage Bond due 11/01/15 1.625%	1,354,166.67	
First Mortgage Bond due 11/01/20 3.250%	5,416,666.67	
First Mortgage Bond due 11/01/40 5.125%	12,812,500.00	
Customers' Deposits	826,007.36	
Other	6,549.05	
Dividends Declared		24,000,000.00
Dividend Payable to LG&E and KU Energy LLC	24,000,000.00	

March 21, 2012

Kentucky Utilities Company
Summary Trial Balance
February 29, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Miscellaneous Current and Accrued Liabilities		$ 18,823,326.42
Vacation Pay Accrued	6,042,349.44	
Tax Collections Payable	4,189,436.29	
Franchise Fee Payable	3,957,701.22	
Customer Overpayments	3,730,690.82	
Home Energy Assistance	509,310.86	
Retirement Income Liability	351,262.96	
Other	42,574.83	
Accumulated Deferred Income Taxes		557,374,045.20
Federal	485,396,785.62	
State	71,977,259.58	
Investment Tax Credit		100,941,082.32
Advanced Coal Credit	98,179,861.00	
Job Development Credit	2,761,221.32	
Regulatory Liabilities		109,273,663.62
Deferred Taxes		
Federal	63,019,714.07	
State	19,772,068.00	
Postretirement Benefits	8,866,251.00	
Environmental Cost Recovery	8,381,767.15	
Asset Retirement Obligations	3,575,864.12	
DSM Cost Recovery	2,496,003.31	
Spare Parts	2,084,702.97	
MISO Schedule 10 Charges	1,077,293.00	
Customers' Advances for Construction		3,145,247.98
Line Extensions	3,139,022.88	
Other	6,225.10	
Asset Retirement Obligations	62,310,870.23	62,310,870.23
Other Deferred Credits	13,197,873.84	13,197,873.84
Miscellaneous Long-Term Liabilities		2,695,347.71
Workers' Compensation	2,695,347.71	
Accumulated Provision for Benefits		135,791,571.26
Pension Payable	68,832,302.39	
Postretirement Benefits - ASC 715	67,213,088.87	
Post Employment Benefits Payable	6,658,395.00	
Post Employment Medicare Subsidy	(364,214.00)	
Medicare Subsidy - ASC 715	(6,548,001.00)	
Total Liabilities and Stockholders Equity	$ 5,193,204,587.60	$ 5,193,204,587.60

March 21, 2012

Kentucky Utilities Company
Statement of Cash Flows
February 29, 2012

	Year to Date	
	2012	2011
Cash Flows from Operating Activities		
Net income	$ 30,377,447.41	$ 42,522,758.25
Items not requiring (providing) cash currently:		
Depreciation	31,272,010.84	29,063,410.68
Amortization	1,295,015.53	1,137,550.42
Deferred income taxes - net	(1,991,943.10)	(315,066.74)
Investment tax credit - net	(454,836.00)	(364,823.00)
Gain on disposal of assets	(1,648.20)	730.18
Other	2,671,075.98	(1,060,516.21)
Change in receivables	2,616,829.79	33,857,928.48
Change in inventory	11,803,283.09	3,401,006.28
Change in allowance inventory	24,399.69	17,561.50
Change in payables and accrued expenses	54,999,588.06	10,663,049.92
Change in regulatory assets	(1,368,076.52)	(64,304,657.56)
Change in regulatory liabilities	960,007.41	65,583,288.03
Change in other deferred debits	(1,161,010.98)	857,956.54
Change in other deferred credits	6,449,559.90	5,943,219.31
Pension and postretirement funding	(15,884,500.00)	(47,954,200.00)
Other	(1,703,155.63)	3,963,094.06
Allowance for other funds used during construction	(4,481.35)	(2,176.10)
Less: Undistributed earnings of subsidiary company	1,391,460.00	(1,319,463.00)
Net cash provided (used) by operating activities	121,291,025.92	81,690,651.04
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(77,569,823.29)	(27,206,130.22)
Less: Allowance for other funds used during construction	4,481.35	2,176.10
Proceeds received from sales of property	1,648.20	(730.18)
Change in non-hedging derivatives	-	(3,775.25)
Change in restricted cash	45,500.00	-
Other	(659,515.88)	(818,050.60)
Net cash provided (used) by investing activities	(78,177,709.62)	(28,026,510.15)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	-	(267,609.95)
Net change in short-term debt	-	(10,434,000.00)
Dividends on common stock	(24,000,000.00)	-
Net cash provided (used) by financing activities	(24,000,000.00)	(10,701,609.95)
Net Increase (Decrease) in Cash and Cash Equivalents	19,113,316.30	42,962,530.94
Cash and Cash Equivalents at Beginning of Period	31,139,814.91	3,333,446.86
Cash and Cash Equivalents at End of Period	$ 50,253,131.21	$ 46,295,977.80

March 21, 2012

Kentucky Utilities Company
Analysis of Interest Charges
February 29, 2012

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Interest on Long-Term Debt						
Loan Agreement - Pollution Control Bonds						
Mercer County 2000 Series A due 05/01/23 Var%..............	$ 1,554.33	$ 2,640.08	$ 2,410.81	$ 5,626.52	$ 21,060.62	$ 41,810.06
Carroll County 2002 Series A due 02/01/32 Var%..............	5,804.36	12,372.11	13,953.33	25,712.37	161,868.23	142,002.91
Carroll County 2002 Series B due 02/01/32 Var%..............	685.25	1,487.14	1,711.47	3,019.20	18,182.76	16,353.99
Carroll County 2002 Series C due 10/01/32 Var%..............	10,496.00	28,416.00	17,109.34	56,688.00	214,832.10	715,959.96
Mercer County 2002 Series A due 02/01/32 Var%..............	2,112.85	4,257.53	5,277.06	8,971.23	55,221.99	50,086.85
Muhlenburg County 2002 Series A due 02/01/32 Var%.......	685.25	1,380.82	1,711.47	2,909.59	17,909.86	16,244.38
Carroll County 2004 Series A due 10/01/34 Var%..............	6,325.16	13,246.58	9,726.79	25,863.02	87,123.98	157,684.94
Carroll County 2006 Series B due 10/01/34 Var%..............	7,140.98	14,898.08	10,711.47	28,390.68	95,158.59	170,580.82
Carroll County 2007 Series A due 02/01/26 5.75%.............	85,651.05	85,651.04	171,302.09	171,302.08	1,027,812.51	1,027,812.49
Trimble County 2007 Series A due 03/01/37 6.00%............	44,635.00	44,635.00	89,270.00	89,270.00	535,620.00	535,620.00
Carroll County 2008 Series A due 02/01/32 Var%..............	10,329.10	20,778.86	15,546.89	40,212.32	136,525.51	245,929.39
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/01/15 1.625%.........................	338,541.67	338,541.67	677,083.34	677,083.34	4,062,499.99	1,184,895.85
First Mortgage Bond due 11/01/20 3.250%.........................	1,354,166.67	1,354,166.67	2,708,333.34	2,708,333.34	16,249,999.99	4,739,583.35
First Mortgage Bond due 11/01/40 5.125%.........................	3,203,125.00	3,203,125.00	6,406,250.00	6,406,250.00	38,437,500.00	11,210,937.50
Fidelia/PPL..	-	-	-	-	-	51,822,277.77
Total..	5,071,252.67	5,125,596.58	10,130,397.40	10,249,631.69	61,121,316.13	72,077,780.26
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense.................................	255,443.25	240,753.22	510,886.50	479,535.61	3,154,584.60	1,027,635.41
Amortization of Loss on Reacquired Debt..............................	50,414.39	50,414.39	100,828.78	100,828.78	604,972.68	604,880.10
Total..	305,857.64	291,167.61	611,715.28	580,364.39	3,759,557.28	1,632,515.51
Other Interest Charges						
Customers' Deposits...	105,283.14	99,420.17	216,661.00	208,573.59	1,371,760.07	1,154,141.75
Other Tax Deficiencies...	-	(90,458.00)	-	(90,458.00)	108,816.75	(2,816.93)
Interest on DSM Cost Recovery...	20.58	1,332.89	(10,837.43)	2,507.30	(1,649.70)	19,002.47
Interest on Debt to Associated Companies..............................	1,181.62	(1,175.77)	1,181.62	2,956.17	4,546.80	112,961.64
AFUDC Borrowed Funds..	(809.42)	(487.45)	(1,566.15)	(946.12)	(13,575.11)	(811,429.48)
Other Interest Expense...	244,388.60	372,931.32	522,487.75	785,216.51	3,715,005.93	2,835,409.02
Total..	350,064.52	381,563.16	727,926.79	907,849.45	5,184,904.74	3,307,268.47
Total Interest..	$ 5,727,174.83	$ 5,798,327.35	$ 11,470,039.47	$ 11,737,845.53	$ 70,065,778.15	$ 77,017,564.24

March 21, 2012

Kentucky Utilities Company
Analysis of Taxes Charged and Accrued
February 29, 2012

Kind of Taxes	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year
Taxes Charged to Accounts 408.1 and 409.1...........				
Property Taxes..	$ 1,740,788.00	$ 1,494,264.00	$ 3,481,576.00	$ 2,988,528.00
Unemployment..	50,785.45	35,341.67	124,509.19	61,788.70
FICA..	611,587.55	592,538.16	1,210,672.52	1,193,038.70
Public Service Commission Fee..............................	168,112.85	157,659.37	336,225.70	315,318.74
Federal Income..	6,931,480.08	8,477,003.58	16,600,043.95	22,036,924.38
State Income...	1,264,099.71	1,059,075.10	3,027,728.38	3,532,008.98
Miscellaneous...	4,626.52	5,087.19	18,103.73	15,850.41
Total Charged to Operating Expense..........	10,771,480.16	11,820,969.07	24,798,859.47	30,143,457.91
Taxes Charged to Other Accounts..........................	(241,000.84)	1,446,866.73	(4,795,580.40)	1,953,524.54
Taxes Accrued on Intercompany Accounts............	(38,725.09)	(277,675.49)	(76,097.23)	(880,323.08)
Total Taxes Charged.................................	$ 10,491,754.23	$ 12,990,160.31	$ 19,927,181.84	$ 31,216,659.37

Analysis of Taxes Accrued - Account 236

Kind of Taxes	Taxes Accrued At Beginning Of Year	Accruals To Date This Year	Payments To Date This Year	Taxes Accrued At End Of Month
Property Taxes..	$ 9,493,201.72	$ 3,481,910.00	$ 10,011.54	$ 12,965,100.18
Unemployment..	70,966.44	112,099.31	21,840.56	161,225.19
FICA..	554,166.20	979,842.31	836,129.42	697,879.09
Federal Income..	0.00	13,182,024.09	0.00	13,182,024.09
State Income...	0.00	1,560,976.77	0.00	1,560,976.77
Kentucky Sales and Use Tax..................................	587,236.42	625,696.67	935,946.00	276,987.09
Miscellaneous...	24,367.21	(15,367.31)	0.00	8,999.90
Totals...	$ 10,729,937.99	$ 19,927,181.84	$ 1,803,927.52	$ 28,853,192.31

March 21, 2012

Kentucky Utilities Company
Summary of Utility Plant
February 29, 2012

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant in Service**						
Electric						
Electric Distribution.................................	$ 1,382,494,206.57	$ 13,444,925.25	$ (968,910.48)	$ (79.97)	$ 12,475,934.80	$ 1,394,970,141.37
Electric General Plant..............................	129,755,046.33	2,142,272.60	-	-	2,142,272.60	131,897,318.93
Electric Hydro Production.......................	17,134,240.66	7,762.58	(322.65)	-	7,439.93	17,141,680.59
Electric Intangible Plant...........................	54,860,528.56	431,970.99	-	-	431,970.99	55,292,499.55
Electric Other Production........................	525,899,447.50	8,136,610.38	(1,765,489.48)	-	6,371,120.90	532,270,568.40
Electric Steam Production.......................	2,659,096,509.86	744,840.58	(2,209,599.51)	-	(1,464,758.93)	2,657,631,750.93
Electric Transmission...............................	574,848,507.91	6,921,288.65	(1,494,756.32)	-	5,426,532.33	580,275,040.24
Total 101 Accounts.................................	5,344,088,487.39	31,829,671.03	(6,439,078.44)	(79.97)	25,390,512.62	5,369,479,000.01
102 **Electric Plant Purchased or Sold**						
Electric						
Electric Steam...	483,341.17	-	-	-	-	483,341.17
Total 102001	483,341.17	-	-	-	-	483,341.17
105 **Plant Held for Future Use**						
Electric						
Electric Distribution.................................	792,599.21	-	-	-	-	792,599.21
Electric Steam...	-	-	-	-	-	-
Total 105001...	792,599.21	-	-	-	-	792,599.21
106 **Completed Construction Not Classified**						
Electric						
Electric Distribution.................................	23,980,094.26	5,171,048.08	-	-	5,171,048.08	29,151,142.34
Electric General Plant..............................	7,738,634.34	229,075.57	-	-	229,075.57	7,967,709.91
Electric Hydro Production.......................	11,505,517.08	109,272.33	-	-	109,272.33	11,614,789.41
Electric Intangible Plant...........................	3,788,766.16	304,668.22	-	-	304,668.22	4,093,434.38
Electric Other Production........................	1,093,637.80	(351,841.60)	-	-	(351,841.60)	741,796.20
Electric Steam Production.......................	967,980,441.51	823,628.45	-	-	823,628.45	968,804,069.96
Electric Transmission...............................	82,036,721.90	5,599,494.73	-	-	5,599,494.73	87,636,216.63
Total 106 Accounts.................................	1,098,123,813.05	11,885,345.78	-	-	11,885,345.78	1,110,009,158.83
121 **Nonutility Property**						
Common						
Non Utility Property................................	179,120.94	-	-	-	-	179,120.94
Total 121001	179,120.94	-	-	-	-	179,120.94
107 **Construction Work In Progress**						
Electric						
Electric..	339,711,431.64	1,199,648.82	-	-	1,199,648.82	340,911,080.46
Total 107001...	339,711,431.64	1,199,648.82	-	-	1,199,648.82	340,911,080.46
Total Plant (Non-CWIP)................................	6,443,667,361.76	43,715,016.81	(6,439,078.44)	(79.97)	37,275,858.40	6,480,943,220.16
Total Plant + CWIP..	6,783,378,793.40	44,914,665.63	(6,439,078.44)	(79.97)	38,475,507.22	6,821,854,300.62
Total Plant + CWIP - Nonutility (BS)............	$ 6,783,199,672.46	$ 44,914,665.63	$ (6,439,078.44)	$ (79.97)	$ 38,475,507.22	$ 6,821,675,179.68

March 21, 2012

Kentucky Utilities Company
Summary of Utility Plant - Reserve for Depreciation of Utility Plant
February 29, 2012

	Beginning Balance	Accruals	Retirements	Transfers/ Adjustments	ARO Settlements	RWIP Transfers Out	Cost of Removal	Salvage	Other Credits	Ending Balance
Life Reserve										
Electric Distribution....................................	$ (411,056,321.05)	$ (4,746,789.64)	$ 968,910.48	$ -	$ -	$ -	$ -	$ -	$ -	$ (414,834,200.21)
Electric Distribution - ARO..........................	(6,765.54)	(5,051.74)	-	(307.57)	-	-	-	-	-	(12,124.85)
Electric General Plant..................................	(54,490,775.21)	(1,140,365.61)	-	-	-	-	-	-	-	(55,631,140.82)
Electric Hydro Production............................	(7,872,943.76)	(33,894.25)	322.65	-	-	-	-	-	-	(7,906,515.36)
Electric Hydro Production - ARO................	(1,094.53)	(162.16)	-	-	-	-	-	-	-	(1,256.69)
Electric Other Production.............................	(175,058,471.14)	(2,828,592.21)	1,765,489.48	-	-	-	-	-	-	(176,121,573.87)
Electric Other Production - ARO.................	(763.60)	(113.14)	-	-	-	-	-	-	-	(876.74)
Electric Steam Production............................	(1,146,202,987.01)	(15,332,999.64)	2,209,599.51	-	-	-	-	-	-	(1,159,326,387.14)
Electric Steam Production - ARO................	(3,512,619.50)	(513,024.20)	-	-	-	-	-	-	-	(4,025,643.70)
Electric Transmission...................................	(217,974,783.91)	(1,609,393.33)	1,494,756.32	-	-	-	-	-	-	(218,089,420.92)
Electric Transmission - ARO.......................	(2,671.85)	(2,726.34)	-	-	-	-	-	-	-	(5,398.19)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(2,016,180,197.10)	(26,213,112.26)	6,439,078.44	(307.57)	-	-	-	-	-	(2,035,954,538.49)
Cost of Removal										
Electric Distribution....................................	(199,658,860.39)	(1,398,141.04)	-	-	-	-	545,002.75	-	-	(200,511,998.68)
Electric General Plant..................................	250,582.68	(8,747.03)	-	-	-	-	-	-	-	241,835.65
Electric Hydro Production............................	(350,001.10)	(883.46)	-	-	-	-	1,776.48	-	-	(349,108.08)
Electric Other Production.............................	(3,572,221.61)	(151,665.52)	-	-	-	-	466,414.71	-	-	(3,257,472.42)
Electric Steam Production............................	(136,295,560.94)	(4,356,182.92)	-	-	-	-	38,412.40	-	-	(140,613,331.46)
Electric Transmission...................................	(138,104,734.27)	(487,913.65)	-	-	-	-	942,860.40	-	-	(137,649,787.52)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(477,730,795.63)	(6,403,533.62)	-	-	-	-	1,994,466.74	-	-	(482,139,862.51)
Salvage										
Electric Distribution....................................	49,559,394.32	341,522.76	-	-	-	-	-	(304,479.06)	-	49,596,438.02
Electric General Plant..................................	137,079.64	-	-	-	-	-	-	-	-	137,079.64
Electric Hydro Production............................	46,518.69	-	-	-	-	-	-	-	-	46,518.69
Electric Other Production.............................	618,891.61	-	-	-	-	-	-	-	-	618,891.61
Electric Steam Production............................	24,235,511.41	821,096.79	-	-	-	-	-	-	-	25,056,608.20
Electric Transmission...................................	23,638,002.34	113,154.96	-	-	-	-	-	(38,262.47)	-	23,712,894.83
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	98,235,398.01	1,275,774.51	-	-	-	-	-	(342,741.53)	-	99,168,430.99
Total Reserves										
Electric Distribution....................................	(561,155,787.12)	(5,803,407.92)	968,910.48	-	-	-	545,002.75	(304,479.06)	-	(565,749,760.87)
Electric Distribution - ARO..........................	(6,765.54)	(5,051.74)	-	(307.57)	-	-	-	-	-	(12,124.85)
Electric General Plant..................................	(54,103,112.89)	(1,149,112.64)	-	-	-	-	-	-	-	(55,252,225.53)
Electric Hydro Production............................	(8,176,426.17)	(34,777.71)	322.65	-	-	-	1,776.48	-	-	(8,209,104.75)
Electric Hydro Production - ARO................	(1,094.53)	(162.16)	-	-	-	-	-	-	-	(1,256.69)
Electric Other Production.............................	(178,011,801.14)	(2,980,257.73)	1,765,489.48	-	-	-	466,414.71	-	-	(178,760,154.68)
Electric Other Production - ARO.................	(763.60)	(113.14)	-	-	-	-	-	-	-	(876.74)
Electric Steam Production............................	(1,258,263,036.54)	(18,868,085.77)	2,209,599.51	-	-	-	38,412.40	-	-	(1,274,883,110.40)
Electric Steam Production - ARO................	(3,512,619.50)	(513,024.20)	-	-	-	-	-	-	-	(4,025,643.70)
Electric Transmission...................................	(332,441,515.84)	(1,984,152.02)	1,494,756.32	-	-	-	942,860.40	(38,262.47)	-	(332,026,313.61)
Electric Transmission - ARO.......................	(2,671.85)	(2,726.34)	-	-	-	-	-	-	-	(5,398.19)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(2,395,675,594.72)	(31,340,871.37)	6,439,078.44	(307.57)	-	-	1,994,466.74	(342,741.53)	-	(2,418,925,970.01)
Retirement Work in Process										
Electric..	18,384,586.20	-	-	-	-	(1,651,725.21)	1,196,122.89	(61,878.39)	(474,728.62)	17,392,376.87
	18,384,586.20	-	-	-	-	(1,651,725.21)	1,196,122.89	(61,878.39)	(474,728.62)	17,392,376.87
YTD ACTIVITY	(2,377,291,008.52)	(31,340,871.37)	6,439,078.44	(307.57)	-	(1,651,725.21)	3,190,589.63	(404,619.92)	(474,728.62)	(2,401,533,593.14)
Amortization										
Electric..	(17,746,764.31)	(1,295,015.53)		-	-	-	-	-	-	(19,041,779.84)
	(17,746,764.31)	(1,295,015.53)	-	-	-	-	-	-	-	(19,041,779.84)
Depreciation & Amortization Total										
Depreciation & Amortization Total..............	(2,395,037,772.83)	(32,635,886.90)	6,439,078.44	(307.57)	-	(1,651,725.21)	3,190,589.63	(404,619.92)	(474,728.62)	(2,420,575,372.98)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)..............	$ 4,388,161,899.63									$ 4,401,099,806.70

March 21, 2012

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of February 29, 2012

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues...................................	$ 126,307,013.69	$ -	$ 126,307,013.69
Rate Refunds...	-	-	-
Total Operating Revenues....................................	126,307,013.69	-	126,307,013.69
Fuel for Electric Generation.....................................	42,542,492.15	-	42,542,492.15
Power Purchased...	7,976,655.49	-	7,976,655.49
Other Operation Expenses.......................................	18,005,230.02	-	18,005,230.02
Maintenance..	12,373,627.51	-	12,373,627.51
Depreciation..	15,657,769.81	-	15,657,769.81
Amortization Expense...	650,767.69	-	650,767.69
Regulatory Credits...	(523,417.91)	-	(523,417.91)
Taxes			
Federal Income..	6,931,480.08	-	6,931,480.08
State Income..	1,264,099.71	-	1,264,099.71
Deferred Federal Income - Net..............................	-	(22,475.59)	(22,475.59)
Deferred State Income - Net..................................	-	(4,098.89)	(4,098.89)
Property and Other..	2,575,900.37	-	2,575,900.37
Loss (Gain) from Disposition of Allowances...........	-	-	-
Accretion Expense...	261,239.52	-	261,239.52
Total Operating Expenses.....................................	107,715,844.44	(26,574.48)	107,689,269.96
Net Operating Income...	18,591,169.25	26,574.48	18,617,743.73
Other Income Less Deductions			
Amortization of Investment Tax Credit.............	233,343.00	-	233,343.00
Other Income Less Deductions..........................	(596,481.22)	(73,840.35)	(670,321.57)
AFUDC - Equity...	3,126.04	-	3,126.04
Total Other Income Less Deductions....................	(360,012.18)	(73,840.35)	(433,852.53)
Income Before Interest Charges............................	18,231,157.07	(47,265.87)	18,183,891.20
Interest on Long-Term Debt....................................	5,071,252.67	(5,525.49)	5,065,727.18
Amortization of Debt Expense - Net........................	305,857.64	-	305,857.64
Other Interest Expenses...	350,873.94	-	350,873.94
AFUDC - Borrowed Funds......................................	(809.42)	-	(809.42)
Total Interest Charges...	5,727,174.83	(5,525.49)	5,721,649.34
Net Income..	$ 12,503,982.24	$ (41,740.38)	$ 12,462,241.86

March 21, 2012

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of February 29, 2012

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues....................................	$ 263,836,314.40	$ -	$ 263,836,314.40
Rate Refunds...	-	-	-
Total Operating Revenues....................................	263,836,314.40	-	263,836,314.40
Fuel for Electric Generation......................................	88,489,053.02	-	88,489,053.02
Power Purchased...	18,834,298.74	-	18,834,298.74
Other Operation Expenses.......................................	37,273,107.51	-	37,273,107.51
Maintenance..	20,099,227.35	-	20,099,227.35
Depreciation..	31,272,010.84	-	31,272,010.84
Amortization Expense...	1,295,015.53	-	1,295,015.53
Regulatory Credits...	(1,042,445.60)	-	(1,042,445.60)
Taxes			
Federal Income..	16,600,043.95	-	16,600,043.95
State Income..	3,027,728.38	-	3,027,728.38
Deferred Federal Income - Net..............................	108,274.01	(44,951.18)	63,322.83
Deferred State Income - Net..................................	0.01	(8,197.78)	(8,197.77)
Property and Other..	5,171,087.14	-	5,171,087.14
Loss (Gain) from Disposition of Allowances...........	-	-	-
Accretion Expense...	521,368.02	-	521,368.02
Total Operating Expenses.....................................	221,648,768.90	(53,148.96)	221,595,619.94
Net Operating Income...	42,187,545.50	53,148.96	42,240,694.46
Other Income Less Deductions			
Amortization of Investment Tax Credit.............	466,686.00	-	466,686.00
Other Income Less Deductions..........................	(812,792.12)	(147,680.70)	(960,472.82)
AFUDC - Equity...	6,047.50	-	6,047.50
Total Other Income Less Deductions.....................	(340,058.62)	(147,680.70)	(487,739.32)
Income Before Interest Charges............................	41,847,486.88	(94,531.74)	41,752,955.14
Interest on Long-Term Debt....................................	10,130,397.40	(11,050.98)	10,119,346.42
Amortization of Debt Expense - Net........................	611,715.28	-	611,715.28
Other Interest Expenses...	729,492.94	-	729,492.94
AFUDC - Borrowed Funds......................................	(1,566.15)	-	(1,566.15)
Total Interest Charges...	11,470,039.47	(11,050.98)	11,458,988.49
Net Income..	$ 30,377,447.41	$ (83,480.76)	$ 30,293,966.65

March 21, 2012

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of February 29, 2012

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,508,988,854.27	$ 15,903,996.75	$ (1,402,334,587.40)	$ (15,348,424.99)	$ 106,654,266.87	$ 555,571.76
Add						
Net Income for Period..	12,503,982.24	-	(41,740.38)	-	12,462,241.86	-
Deductions:						
Common Dividends						
Common Stock Without Par Value..................	(24,000,000.00)	-	-	-	(24,000,000.00)	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc..	939,862.00	(939,862.00)	73,840.35	(73,840.35)	1,013,702.35	(1,013,702.35)
Balance at End of Period	$ 1,498,432,698.51	$ 14,964,134.75	$ (1,402,302,487.43)	$ (15,422,265.34)	$ 96,130,211.08	$ (458,130.59)
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings................		14,964,134.75		(15,422,265.34)		(458,130.59)
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.........................		$ 5,821,048.42		$ (5,999,261.22)		$ (178,212.80)

March 21, 2012

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of February 29, 2012

Retained Earnings and Undistributed Earnings	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Combined	
	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,490,663,791.10	$ 16,355,594.75	$ (1,402,366,687.37)	$ (15,274,584.64)	$ 88,297,103.73	$ 1,081,010.11
Add						
Net Income for Period ………………………………	30,377,447.41	-	(83,480.76)	-	30,293,966.65	-
Deductions:						
Common Dividends						
Common Stock Without Par Value...................	(24,000,000.00)	-	-	-	(24,000,000.00)	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc……………………….…………	1,391,460.00	(1,391,460.00)	147,680.70	(147,680.70)	1,539,140.70	(1,539,140.70)
Balance at End of Period …...……………………………	$ 1,498,432,698.51	$ 14,964,134.75	$ (1,402,302,487.43)	$ (15,422,265.34)	$ 96,130,211.08	$ (458,130.59)
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings…………		14,964,134.75		(15,422,265.34)		(458,130.59)
Statutory Tax Rate…...…………………………………		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary…...………………		$ 5,821,048.42		$ (5,999,261.22)		$ (178,212.80)

March 21, 2012

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of February 29, 2012

Retained Earnings and Undistributed Earnings	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,449,554,889.07	$ 15,751,858.75	$ (1,403,125,943.09)	$ (14,536,181.14)	$ 46,428,945.98	$ 1,215,677.61
Add						
Net Income for Period...	164,590,085.44	-	(62,628.54)	-	164,527,456.90	-
Deductions:						
Common Dividends						
Common Stock Without Par Value....................	(116,500,000.00)	-	-	-	(116,500,000.00)	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	787,724.00	(787,724.00)	886,084.20	(886,084.20)	1,673,808.20	(1,673,808.20)
Balance at End of Period	$ 1,498,432,698.51	$ 14,964,134.75	$ (1,402,302,487.43)	$ (15,422,265.34)	$ 96,130,211.08	$ (458,130.59)

Deferred Taxes Related to Undistributed Subsidiary Earnings	Without Purchase Accounting	Purchase Accounting	Combined
Balance of Undistributed Subsidiary Earnings.................	14,964,134.75	(15,422,265.34)	(458,130.59)
Statutory Tax Rate...	38.9%	38.9%	38.9%
Deferred Taxes on Equity in Subsidiary...........................	$ 5,821,048.42	$ (5,999,261.22)	$ (178,212.80)

Combined Balance of Retained Earnings	12 MONTHS 2/29/2012	12 MONTHS 2/28/2011
Retained Earnings at Beginning of Period........................	$ 47,644,623.59	$ 1,378,241,422.22
Net Income for Period	164,527,456.90	168,727,587.97
FIN 48 Adjustment...	-	-
Subtotal..	212,172,080.49	1,546,969,010.19
Deduct		
Purchase Accounting Adjustment................................	-	1,418,324,386.60
Dividends on Common Stock.....................................	116,500,000.00	81,000,000.00
Retained Earnings at End of Period.................................	$ 95,672,080.49	$ 47,644,623.59

March 21, 2012

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of February 29, 2012

Assets	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 6,821,675,179.68	$ -	$ 6,821,675,179.68
Less Reserves for Depreciation and Amortization.....	2,420,575,372.98	-	2,420,575,372.98
Total..	4,401,099,806.70	-	4,401,099,806.70
Investments			
Electric Energy, Inc...	6,914,711.55	16,540,237.41	23,454,948.96
Ohio Valley Electric Corporation.............................	250,000.00	-	250,000.00
Nonutility Property - Less Reserve...........................	179,120.94	-	179,120.94
Special Funds...	-	-	-
Total..	7,343,832.49	16,540,237.41	23,884,069.90
Current and Accrued Assets			
Cash..	37,207,894.02	-	37,207,894.02
Special Deposits..	-	-	-
Temporary Cash Investments.................................	13,045,237.19	-	13,045,237.19
Accounts Receivable-Less Reserve........................	163,002,243.65	-	163,002,243.65
Accounts Receivable from Assoc Companies..........	-	-	-
Materials & Supplies-At Average Cost			
Fuel..	84,398,050.88	-	84,398,050.88
Plant Materials & Operating Supplies..................	34,371,771.07	-	34,371,771.07
Stores Expense..	10,204,327.46	-	10,204,327.46
Allowance Inventory..	426,062.63	-	426,062.63
Prepayments..	7,005,733.57	-	7,005,733.57
Miscellaneous Current & Accrued Assets..............	-	-	-
Total..	349,661,320.47	-	349,661,320.47
Deferred Debits and Other			
Unamortized Debt Expense......................................	21,195,901.47	(4,373,640.49)	16,822,260.98
Unamortized Loss on Bonds....................................	11,674,288.59	-	11,674,288.59
Accumulated Deferred Income Taxes.......................	86,638,419.05	57,520,733.36	144,159,152.41
Deferred Regulatory Assets.....................................	270,129,911.18	10,498,909.89	280,628,821.07
Other Deferred Debits..	45,461,107.65	135,813,758.67	181,274,866.32
Goodwill..	-	607,404,368.23	607,404,368.23
Total..	435,099,627.94	806,864,129.66	1,241,963,757.60
Total Assets..	$ 5,193,204,587.60	$ 823,404,367.07	$ 6,016,608,954.67

March 21, 2012

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of February 29, 2012

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Proprietary Capital			
Common Stock...	$ 308,139,977.56	$ -	$ 308,139,977.56
Less: Common Stock Expense.....................................	321,288.87	-	321,288.87
Paid-In Capital...	315,858,083.00	2,032,588,750.94	2,348,446,833.94
Other Comprehensive Income.....................................	(5,692,006.25)	1,990,823.26	(3,701,182.99)
Retained Earnings..	1,498,432,698.51	(1,402,302,487.43)	96,130,211.08
Unappropriated Undistributed Subsidiary Earnings....	14,964,134.75	(15,422,265.34)	(458,130.59)
Total Proprietary Capital..	2,131,381,598.70	616,854,821.43	2,748,236,420.13
Pollution Control Bonds - Net of Reacquired Bonds...	350,779,405.00	1,073,047.15	351,852,452.15
First Mortgage Bonds..	1,489,918,031.25	-	1,489,918,031.25
Total Long-Term Debt...	1,840,697,436.25	1,073,047.15	1,841,770,483.40
Total Capitalization..	3,972,079,034.95	617,927,868.58	4,590,006,903.53
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Accounts Payable...	91,837,948.35	-	91,837,948.35
Accounts Payable to Associated Companies................	28,944,224.53	-	28,944,224.53
Customer Deposits...	23,087,288.98	-	23,087,288.98
Taxes Accrued..	28,853,192.31	-	28,853,192.31
Interest Accrued...	20,849,869.90	-	20,849,869.90
Dividends Declared..	24,000,000.00	-	24,000,000.00
Miscellaneous Current and Accrued Liabilities...........	18,823,326.42	-	18,823,326.42
Total..	236,395,850.49	-	236,395,850.49
Deferred Credits and Other			
Accumulated Deferred Income Taxes..........................	557,374,045.20	63,537,470.42	620,911,515.62
Investment Tax Credit..	100,941,082.32	-	100,941,082.32
Regulatory Liabilities...	109,273,663.62	135,813,758.67	245,087,422.29
Customer Advances for Construction..........................	3,145,247.98	-	3,145,247.98
Asset Retirement Obligations......................................	62,310,870.23	-	62,310,870.23
Other Deferred Credits...	13,197,873.84	6,125,269.40	19,323,143.24
Miscellaneous Long-Term Liabilities...........................	2,695,347.71	-	2,695,347.71
Accum Provision for Postretirement Benefits.............	135,791,571.26	-	135,791,571.26
Total..	984,729,702.16	205,476,498.49	1,190,206,200.65
Total Liabilities and Stockholders' Equity.........................	$ 5,193,204,587.60	$ 823,404,367.07	$ 6,016,608,954.67

March 21, 2012

KENTUCKY UTILITIES COMPANY

Financial Reports

January 31, 2012

Index
Financial and Operating Reports

Kentucky Utilities Company
January 31, 2012

Certain reclassification entries have been made to prior financial statements to conform to the current presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows, unless otherwise noted.

Kentucky Utilities Company
Comparative Statement of Income
January 31, 2012

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 137,529,300.71	$ 153,232,654.15	$ (15,703,353.44)	(10.25)
Rate Refunds	-	-	-	-
Total Operating Revenues	137,529,300.71	153,232,654.15	(15,703,353.44)	(10.25)
Fuel for Electric Generation	45,946,560.87	49,735,324.55	(3,788,763.68)	(7.62)
Power Purchased	10,857,643.25	13,884,136.77	(3,026,493.52)	(21.80)
Other Operation Expenses	19,267,877.49	18,481,340.00	786,537.49	4.26
Maintenance	7,725,599.84	7,399,927.73	325,672.11	4.40
Depreciation	15,614,241.03	13,966,907.69	1,647,333.34	11.79
Amortization Expense	644,247.84	564,264.60	79,983.24	14.17
Regulatory Credits	(519,027.69)	(468,758.07)	(50,269.62)	(10.72)
Taxes				
Federal Income	9,668,563.87	13,559,920.80	(3,891,356.93)	(28.70)
State Income	1,763,628.67	2,472,933.88	(709,305.21)	(28.68)
Deferred Federal Income - Net	108,274.01	(1.45)	108,275.46	7,467,273.10
Deferred State Income - Net	0.01	-	0.01	100.00
Property and Other	2,595,186.77	2,289,634.16	305,552.61	13.35
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	-	-	-	-
Accretion Expense	260,128.50	224,626.83	35,501.67	15.80
Total Operating Expenses	113,932,924.46	122,110,257.49	(8,177,333.03)	(6.70)
Net Operating Income	23,596,376.25	31,122,396.66	(7,526,020.41)	(24.18)
Other Income Less Deductions				
Amortization of Investment Tax Credit	233,343.00	119,632.00	113,711.00	95.05
Other Income Less Deductions	(216,310.90)	(144,046.50)	(72,264.40)	(50.17)
AFUDC - Equity	2,921.46	1,513.63	1,407.83	93.01
Total Other Income Less Deductions	19,953.56	(22,900.87)	42,854.43	187.13
Income Before Interest Charges	23,616,329.81	31,099,495.79	(7,483,165.98)	(24.06)
Interest on Long-Term Debt	5,059,144.73	5,124,035.11	(64,890.38)	(1.27)
Amortization of Debt Expense - Net	305,857.64	289,196.78	16,660.86	5.76
Other Interest Expenses	378,619.00	526,744.96	(148,125.96)	(28.12)
AFUDC - Borrowed Funds	(756.73)	(458.67)	(298.06)	(64.98)
Total Interest Charges	5,742,864.64	5,939,518.18	(196,653.54)	(3.31)
Net Income	$ 17,873,465.17	$ 25,159,977.61	$ (7,286,512.44)	(28.96)

February 21, 2012

Kentucky Utilities Company
Comparative Statement of Income
January 31, 2012

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues......................................	$ 137,529,300.71	$ 153,232,654.15	$ (15,703,353.44)	(10.25)
Rate Refunds...	-	-	-	-
Total Operating Revenues.......................................	137,529,300.71	153,232,654.15	(15,703,353.44)	(10.25)
Fuel for Electric Generation......................................	45,946,560.87	49,735,324.55	(3,788,763.68)	(7.62)
Power Purchased...	10,857,643.25	13,884,136.77	(3,026,493.52)	(21.80)
Other Operation Expenses..	19,267,877.49	18,481,340.00	786,537.49	4.26
Maintenance..	7,725,599.84	7,399,927.73	325,672.11	4.40
Depreciation..	15,614,241.03	13,966,907.69	1,647,333.34	11.79
Amortization Expense...	644,247.84	564,264.60	79,983.24	14.17
Regulatory Credits..	(519,027.69)	(468,758.07)	(50,269.62)	(10.72)
Taxes				
Federal Income...	9,668,563.87	13,559,920.80	(3,891,356.93)	(28.70)
State Income...	1,763,628.67	2,472,933.88	(709,305.21)	(28.68)
Deferred Federal Income - Net...............................	108,274.01	(1.45)	108,275.46	7,467,273.10
Deferred State Income - Net...................................	0.01	-	0.01	100.00
Property and Other...	2,595,186.77	2,289,634.16	305,552.61	13.35
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances............	-	-	-	-
Accretion Expense..	260,128.50	224,626.83	35,501.67	15.80
Total Operating Expenses......................................	113,932,924.46	122,110,257.49	(8,177,333.03)	(6.70)
Net Operating Income...	23,596,376.25	31,122,396.66	(7,526,020.41)	(24.18)
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	233,343.00	119,632.00	113,711.00	95.05
Other Income Less Deductions...........................	(216,310.90)	(144,046.50)	(72,264.40)	(50.17)
AFUDC - Equity...	2,921.46	1,513.63	1,407.83	93.01
Total Other Income Less Deductions.....................	19,953.56	(22,900.87)	42,854.43	187.13
Income Before Interest Charges.............................	23,616,329.81	31,099,495.79	(7,483,165.98)	(24.06)
Interest on Long-Term Debt......................................	5,059,144.73	5,124,035.11	(64,890.38)	(1.27)
Amortization of Debt Expense - Net.........................	305,857.64	289,196.78	16,660.86	5.76
Other Interest Expenses..	378,619.00	526,744.96	(148,125.96)	(28.12)
AFUDC - Borrowed Funds.......................................	(756.73)	(458.67)	(298.06)	(64.98)
Total Interest Charges..	5,742,864.64	5,939,518.18	(196,653.54)	(3.31)
Net Income..	$ 17,873,465.17	$ 25,159,977.61	$ (7,286,512.44)	(28.96)

February 21, 2012

Kentucky Utilities Company
Comparative Statement of Income
January 31, 2012

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues.....................................	$ 1,531,813,632.66	$ 1,528,859,365.42	$ 2,954,267.24	0.19
Rate Refunds..	-	(173,614.71)	173,614.71	100.00
Total Operating Revenues......................................	1,531,813,632.66	1,528,685,750.71	3,127,881.95	0.20
Fuel for Electric Generation......................................	518,859,878.43	495,338,885.39	23,520,993.04	4.75
Power Purchased..	106,088,454.22	169,239,433.54	(63,150,979.32)	(37.31)
Other Operation Expenses..	234,295,228.43	218,583,287.81	15,711,940.62	7.19
Maintenance..	116,629,040.80	107,252,284.93	9,376,755.87	8.74
Depreciation..	183,574,121.46	142,487,513.90	41,086,607.56	28.84
Amortization Expense...	7,343,427.65	6,595,593.58	747,834.07	11.34
Regulatory Credits..	(5,905,909.55)	(5,412,983.41)	(492,926.14)	(9.11)
Taxes				
Federal Income..	(10,832,809.04)	67,956,215.64	(78,789,024.68)	(115.94)
State Income..	3,745,873.94	13,904,738.95	(10,158,865.01)	(73.06)
Deferred Federal Income - Net...............................	101,697,054.49	22,275,450.30	79,421,604.19	356.54
Deferred State Income - Net...................................	9,974,459.80	3,311,038.18	6,663,421.62	201.25
Property and Other..	28,421,319.07	20,390,740.45	8,030,578.62	39.38
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances...........	(3,293.39)	(56,750.74)	53,457.35	94.20
Accretion Expense..	2,862,618.53	3,543,058.42	(680,439.89)	(19.20)
Total Operating Expenses......................................	1,296,749,464.84	1,265,408,506.94	31,340,957.90	2.48
Net Operating Income..	235,064,167.82	263,277,243.77	(28,213,075.95)	(10.72)
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	2,800,112.00	187,682.00	2,612,430.00	1,391.94
Other Income Less Deductions...........................	1,677,465.28	399,001.50	1,278,463.78	320.42
AFUDC - Equity...	44,069.41	534,798.81	(490,729.40)	(91.76)
Total Other Income Less Deductions.....................	4,521,646.69	1,121,482.31	3,400,164.38	303.18
Income Before Interest Charges.............................	239,585,814.51	264,398,726.08	(24,812,911.57)	(9.38)
Interest on Long-Term Debt......................................	61,175,660.04	73,256,197.25	(12,080,537.21)	(16.49)
Amortization of Debt Expense - Net.........................	3,744,867.25	1,409,743.49	2,335,123.76	165.64
Other Interest Expenses..	5,229,656.52	3,963,554.92	1,266,101.60	31.94
AFUDC - Borrowed Funds.......................................	(13,253.14)	(890,499.71)	877,246.57	98.51
Total Interest Charges..	70,136,930.67	77,738,995.95	(7,602,065.28)	(9.78)
Net Income..	$ 169,448,883.84	$ 186,659,730.13	$ (17,210,846.29)	(9.22)

February 21, 2012

Kentucky Utilities Company
Analysis of Retained Earnings
January 31, 2012

Retained Earnings and Undistributed Earnings	Current Month		Year to Date		Year Ended Current Month	
	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period..	$ 1,490,663,791.10	$ 16,355,594.75	$ 1,490,663,791.10	$ 16,355,594.75	$ 1,464,645,446.43	$ 14,298,520.75
Add:						
Net Income for Period..	17,873,465.17	-	17,873,465.17	-	169,448,883.84	-
Deduct:						
Common Dividends						
Common Stock Without Par Value	-	-	-	-	(123,500,000.00)	-
EE Inc..	451,598.00	(451,598.00)	451,598.00	(451,598.00)	(1,605,476.00)	1,605,476.00
Balance at End of Period..	$ 1,508,988,854.27	$ 15,903,996.75	$ 1,508,988,854.27	$ 15,903,996.75	$ 1,508,988,854.27	$ 15,903,996.75
Deferred Taxes Related to Undistributed Subsidiary Earnings		-		-		-
Balance of Undistributed Subsidiary Earnings.............................		15,903,996.75		15,903,996.75		15,903,996.75
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.......................................		$ 6,186,654.74		$ 6,186,654.74		$ 6,186,654.74

February 21, 2012

Kentucky Utilities Company
Comparative Balance Sheets as of January 31, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,803,462,666.78	$ 6,504,302,691.20
Less: Reserves for Depreciation and Amortization	2,410,391,836.92	2,272,048,734.84
Total	4,393,070,829.86	4,232,253,956.36
Investments		
Electric Energy, Inc.	7,808,493.55	11,490,952.55
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	179,120.94	179,120.94
Total	8,237,614.49	11,920,073.49
Current and Accrued Assets		
Cash	34,865,584.78	9,914,406.17
Special Deposits	45,500.00	434,339.60
Temporary Cash Investments	43,949.50	905.14
Accounts Receivable-Less Reserve	170,930,926.96	196,311,231.99
Accounts Receivable from Associated Companies	37,600.00	12,676.56
Materials and Supplies-At Average Cost		
Fuel	87,935,980.78	87,822,625.41
Plant Materials and Operating Supplies	34,252,319.17	32,915,292.79
Stores Expense	10,051,772.10	9,036,735.24
Emission Allowances	437,931.35	557,408.56
Prepayments	6,716,116.70	9,131,948.98
Miscellaneous Current and Accrued Assets	-	67,990.24
Total	345,317,681.34	346,205,560.68
Deferred Debits and Other		
Unamortized Debt Expense	21,398,407.22	21,040,297.83
Unamortized Loss on Bonds	11,724,702.98	12,329,675.66
Accumulated Deferred Income Taxes	86,638,419.05	98,973,011.75
Deferred Regulatory Assets	270,161,197.40	275,242,950.03
Other Deferred Debits	45,344,944.06	42,482,956.65
Total	435,267,670.71	450,068,891.92
Total Assets	$ 5,181,893,796.40	$ 5,040,448,482.45

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	315,858,083.00	315,858,083.00
Other Comprehensive Income	(5,738,086.25)	(2,507,157.97)
Retained Earnings	1,508,988,854.27	1,464,645,446.43
Unappropriated Undistributed Subsidiary Earnings	15,903,996.75	14,298,520.75
Total Proprietary Capital	2,142,831,536.46	2,100,113,580.90
Pollution Control Bonds	350,779,405.00	350,779,405.00
First Mortgage Bonds	1,489,865,093.75	1,489,229,843.75
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,840,644,498.75	1,840,009,248.75
Total Capitalization	3,983,476,035.21	3,940,122,829.65
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	4,319,000.00
Accounts Payable	102,021,113.92	69,011,148.54
Accounts Payable to Associated Companies	30,032,920.51	34,024,289.41
Customer Deposits	22,803,107.92	22,764,194.58
Taxes Accrued	19,135,631.20	39,565,027.61
Interest Accrued	15,717,741.67	13,289,829.81
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	23,113,050.25	22,136,246.71
Total	212,823,565.47	205,109,736.66
Deferred Credits and Other		
Accumulated Deferred Income Taxes	557,374,045.20	460,742,213.58
Investment Tax Credit	101,174,425.32	103,974,537.32
Regulatory Liabilities	111,812,562.27	121,838,285.24
Customer Advances for Construction	3,149,042.71	2,868,115.32
Asset Retirement Obligations	62,049,630.71	54,205,933.24
Other Deferred Credits	11,537,934.99	13,148,117.87
Miscellaneous Long-Term Liabilities	2,695,347.71	2,422,714.13
Accum Provision for Postretirement Benefits	135,801,206.81	136,015,999.44
Total	985,594,195.72	895,215,916.14
Total Liabilities and Stockholders Equity	$ 5,181,893,796.40	$ 5,040,448,482.45

February 21, 2012

Kentucky Utilities Company
Statement of Capitalization and Short-Term Debt
January 31, 2012

	Authorized	Issued and Outstanding		Percent of Total
	Shares	Shares	Amount	Capital
Proprietary Capital				
Common Stock - Without Par	80,000,000	37,817,878	$ 308,139,977.56	
Less: Common Stock Expense			321,288.87	
Paid-In Capital			315,858,083.00	
Other Comprehensive Income			(5,738,086.25)	
Retained Earnings			1,508,988,854.27	
Unappropriated Undistributed Subsidiary Earnings			15,903,996.75	
Total Proprietary Capital			2,142,831,536.46	53.79
Long-Term Debt				
Pollution Control Bonds				
Mercer County 2000 Series A due 05/01/23 Var%			12,900,000.00	
Carroll County 2002 Series A due 02/01/32 Var%			20,930,000.00	
Carroll County 2002 Series B due 02/01/32 Var%			2,400,000.00	
Carroll County 2002 Series C due 10/01/32 Var%			96,000,000.00	
Mercer County 2002 Series A due 02/01/32 Var%			7,400,000.00	
Muhlenburg County 2002 Series A due 02/01/32 Var%			2,400,000.00	
Carroll County 2004 Series A due 10/01/34 Var%			50,000,000.00	
Carroll County 2006 Series B due 10/01/34 Var%			54,000,000.00	
Carroll County 2007 Series A due 02/01/26 5.75%			17,875,000.00	
Trimble County 2007 Series A due 03/01/37 6.00%			8,927,000.00	
Carroll County 2008 Series A due 02/01/32 Var%			77,947,405.00	
Total Pollution Control Bonds			350,779,405.00	8.81
First Mortgage Bonds				
First Mortgage Bond due 11/01/15 1.625%			250,000,000.00	
First Mortgage Bond due 11/01/20 3.250%			500,000,000.00	
First Mortgage Bond due 11/01/40 5.125%			750,000,000.00	
Total First Mortgage Bonds			1,500,000,000.00	37.66
Less: First Mortgage Bonds Debt Discount				
First Mortgage Bond due 11/01/15 1.625%			(663,541.69)	
First Mortgage Bond due 11/01/20 3.250%			(1,661,625.00)	
First Mortgage Bond due 11/01/40 5.125%			(7,809,739.56)	
			(10,134,906.25)	(0.26)
Total First Mortgage Bonds - Net of Debt Discount			1,489,865,093.75	37.40
Total Capitalization			$ 3,983,476,035.21	100.00

February 21, 2012

Kentucky Utilities Company
Summary Trial Balance
January 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 6,803,462,666.78	$ 6,803,462,666.78
Reserves for Depreciation and Amortization		(2,410,391,836.92)
Depreciation of Plant	(2,392,000,824.77)	
Amortization of Plant	(18,391,012.15)	
Investments		8,237,614.49
Electric Energy, Inc	7,808,493.55	
Ohio Valley Electric Corporation	250,000.00	
Nonutility Property Reserve	179,120.94	
Cash	34,865,584.78	34,865,584.78
Special Deposits		45,500.00
Restricted Cash	45,500.00	
Temporary Cash Investments	43,949.50	43,949.50
Accounts Receivable - Less Reserve		170,930,926.96
Unbilled Revenues	83,364,119.72	
Customers - Active	82,215,577.49	
IMPA	1,458,356.34	
IMEA	1,371,926.73	
Transmission Sales	1,251,471.81	
Damage Claims	271,534.62	
Bechtel Liquidated Damages	25,110.00	
Sundry Accounts Receivable	21,556.32	
Other	3,131,742.69	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	838,571.13	
Reserve	(2,073,207.00)	
Accrual	(751,055.16)	
Recoveries	(87,515.97)	
A/R Miscellaneous	(81,529.63)	
LEM Reserve	(25,732.13)	
Accounts Receivable from Associated Companies		37,600.00
LG&E and KU Services/Louisville Gas and Electric Company	37,600.00	
Fuel		87,935,980.78
Coal 1,376,435.56 Tons @ $58.52 MMBtu 31,161,047.87 @ 258.50¢	80,551,417.07	
Fuel Oil 2,917,356 Gallons @ 251.33¢	7,332,293.55	
Gas Pipeline 14,306.81 Mcf @ $3.65	52,270.16	
Plant Materials and Operating Supplies		34,252,319.17
Regular Materials and Supplies	33,438,302.83	
Limestone 86,097.41 Tons @ $9.45	814,016.30	
Other Reagents	0.04	
Stores Expense Undistributed	10,051,772.10	10,051,772.10

February 21, 2012

Kentucky Utilities Company
Summary Trial Balance
January 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Emission Allowances	$ 437,931.35	$ 437,931.35
Prepayments		6,716,116.70
Insurance	2,587,754.38	
Taxes	840,564.31	
Lease	581,099.90	
Risk Management and Workers Compensation	75,000.00	
Other	2,631,698.11	
Unamortized Debt Expense		21,398,407.22
Carroll County 2002 Series A due 02/01/32 Var%	82,002.34	
Carroll County 2002 Series B due 02/01/32 Var%	56,991.62	
Carroll County 2002 Series C due 10/01/32 Var%	1,522,265.17	
Mercer County 2002 Series A due 02/01/32 Var%	22,893.40	
Muhlenburg County 2002 Series A due 02/01/32 Var%	63,442.11	
Carroll County 2006 Series B due 10/01/34 Var%	1,086,187.40	
Carroll County 2007 Series A due 02/01/26 5.75%	466,789.74	
Trimble County 2007 Series A due 03/01/37 6.00%	403,131.23	
Carroll County 2008 Series A due 02/01/32 Var%	687,993.45	
First Mortgage Bond due 11/01/15 1.625%	1,742,623.31	
First Mortgage Bond due 11/01/20 3.250%	3,674,640.93	
First Mortgage Bond due 11/01/40 5.125%	7,186,445.73	
Revolving Credit Agreement	4,403,000.79	
Unamortized Loss on Bonds		11,724,702.98
Refinanced and Called Bonds	11,724,702.98	
Accumulated Deferred Income Taxes		86,638,419.05
Federal	73,166,692.83	
State	13,471,726.22	
Regulatory Assets		270,161,197.40
Pension and Postretirement Benefits	113,455,867.00	
ASC 740 - Deferred Taxes	75,212,354.54	
2009 Winter Storm	48,651,244.78	
Asset Retirement Obligations	7,940,627.30	
FERC Jurisdictional Pension Expense	5,958,988.92	
Virginia Mountain Snowstorm	5,739,586.62	
MISO Exit Fee	3,537,233.63	
VA Fuel Component Non-Current	3,328,000.00	
2008 Wind Storm	1,866,188.89	
Environmental Cost Recovery	1,855,750.00	
Rate Case Expenses	1,045,664.21	
EKPC FERC Transmission Cost	697,285.56	
KCCS Funding	576,225.32	
CMRG Funding	153,659.94	
General Management Audit	142,520.69	
Other Deferred Debits	45,344,944.06	45,344,944.06
Total Assets	$ 5,181,893,796.40	$ 5,181,893,796.40

February 21, 2012

Kentucky Utilities Company
Summary Trial Balance
January 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 2,142,831,536.46
Common Stock	308,139,977.56	
Less: Common Stock Expense	321,288.87	
Paid-In Capital	315,858,083.00	
Other Comprehensive Income	(5,738,086.25)	
Retained Earnings	1,508,988,854.27	
Unappropriated Undistributed Subsidiary Earnings	15,903,996.75	
Bonds		1,840,644,498.75
First Mortgage Bonds	1,489,865,093.75	
Pollution Control Bonds - Net of Reacquired Bonds	350,779,405.00	
Accounts Payable		102,021,113.92
Regular	94,096,252.56	
Employee Withholdings Payable	4,723,415.44	
Salaries and Wages Accrued	3,201,445.92	
Accounts Payable to Associated Companies		30,032,920.51
LG&E and KU Services/Louisville Gas and Electric Company	30,032,920.51	
Customers' Deposits	22,803,107.92	22,803,107.92
Taxes Accrued	19,135,631.20	19,135,631.20
Interest Accrued		15,717,741.67
Mercer County 2000 Series A due 05/01/23 Var%	778.94	
Carroll County 2002 Series A due 02/01/32 Var%	2,802.10	
Carroll County 2002 Series B due 02/01/32 Var%	918.03	
Carroll County 2002 Series C due 10/01/32 Var%	2,986.67	
Mercer County 2002 Series A due 02/01/32 Var%	2,830.60	
Muhlenburg County 2002 Series A due 02/01/32 Var%	918.03	
Carroll County 2004 Series A due 10/01/34 Var%	3,046.44	
Carroll County 2006 Series B due 10/01/34 Var%	3,275.41	
Carroll County 2007 Series A due 02/01/26 5.75%	171,302.08	
Trimble County 2007 Series A due 03/01/37 6.00%	89,270.00	
Carroll County 2008 Series A due 02/01/32 Var%	4,749.25	
First Mortgage Bond due 11/01/15 1.625%	1,015,625.00	
First Mortgage Bond due 11/01/20 3.250%	4,062,500.00	
First Mortgage Bond due 11/01/40 5.125%	9,609,375.00	
Customers' Deposits	740,835.65	
Other	6,528.47	

February 21, 2012

Kentucky Utilities Company
Summary Trial Balance
January 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Miscellaneous Current and Accrued Liabilities		$ 23,113,050.25
Franchise Fee Payable	6,782,633.63	
Vacation Pay Accrued	6,042,349.44	
Customer Overpayments	4,925,848.98	
Tax Collections Payable	4,523,536.55	
Home Energy Assistance	440,642.96	
Retirement Income Liability	351,262.96	
Other	46,775.73	
Accumulated Deferred Income Taxes		557,374,045.20
Federal	485,396,785.62	
State	71,977,259.58	
Investment Tax Credit		101,174,425.32
Advanced Coal Credit	98,407,279.00	
Job Development Credit	2,767,146.32	
Regulatory Liabilities		111,812,562.27
Deferred Taxes		
Federal	63,019,714.07	
State	19,772,068.00	
Environmental Cost Recovery	11,019,855.15	
Postretirement Benefits	8,866,251.00	
Asset Retirement Obligations	3,554,730.84	
DSM Cost Recovery	2,431,846.72	
Spare Parts	2,084,702.97	
MISO Schedule 10 Charges	1,060,393.52	
Fuel Adjustment Clause	3,000.00	
Customers' Advances for Construction		3,149,042.71
Line Extensions	2,979,159.63	
Other	169,883.08	
Asset Retirement Obligations	62,049,630.71	62,049,630.71
Other Deferred Credits	11,537,934.99	11,537,934.99
Miscellaneous Long-Term Liabilities		2,695,347.71
Workers' Compensation	2,695,347.71	
Accumulated Provision for Benefits		135,801,206.81
Pension Payable	68,832,302.39	
Postretirement Benefits - ASC 715	67,222,724.42	
Post Employment Benefits Payable	6,658,395.00	
Post Employment Medicare Subsidy	(364,214.00)	
Medicare Subsidy - ASC 715	(6,548,001.00)	
Total Liabilities and Stockholders Equity	$ 5,181,893,796.40	$ 5,181,893,796.40

February 21, 2012

Kentucky Utilities Company
Statement of Cash Flows
January 31, 2012

	Year to Date	
	2012	2011
Cash Flows from Operating Activities		
Net income	$ 17,873,465.17	$ 25,159,977.61
Items not requiring (providing) cash currently:		
Depreciation	15,614,241.03	13,966,907.69
Amortization	644,247.84	564,264.60
Deferred income taxes - net	(1,986,018.10)	(320,991.74)
Investment tax credit - net	(227,418.00)	(125,555.00)
Gain on disposal of assets	-	365.09
Other	(791,934.13)	340,327.72
Change in receivables	(5,579,557.93)	15,245,961.28
Change in inventory	8,534,375.29	6,539,017.40
Change in allowance inventory	12,530.97	9,170.44
Change in payables and accrued expenses	9,548,629.05	19,675,214.94
Change in regulatory assets	(1,265,709.66)	(66,839,594.59)
Change in regulatory liabilities	3,498,906.06	66,725,654.84
Change in other deferred debits	(223,732.22)	304,644.42
Change in other deferred credits	4,789,255.96	4,875,578.62
Pension and postretirement funding	(15,884,500.00)	(20,324,342.00)
Other	754,590.95	(25,554,725.65)
Allowance for other funds used during construction	(2,164.73)	(1,972.30)
Less: Undistributed earnings of subsidiary company	451,598.00	133,875.00
Net cash provided (used) by operating activities	35,760,805.55	40,373,778.37
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(31,413,306.94)	(27,285,189.86)
Less: Allowance for other funds used during construction	2,164.73	1,972.30
Proceeds received from sales of property	-	(365.09)
Change in non-hedging derivatives	-	(15.07)
Change in restricted cash	-	-
Other	(579,943.97)	(380,816.20)
Net cash provided (used) by investing activities	(31,991,086.18)	(27,664,413.92)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	-	(12,500.00)
Payments for retirement of long-term debt	-	-
Net change in short-term debt	-	(6,115,000.00)
Dividends on common stock	-	-
Net cash provided (used) by financing activities	-	(6,127,500.00)
Net Increase (Decrease) in Cash and Cash Equivalents	3,769,719.37	6,581,864.45
Cash and Cash Equivalents at Beginning of Period	31,139,814.91	3,333,446.86
Cash and Cash Equivalents at End of Period	$ 34,909,534.28	$ 9,915,311.31

February 21, 2012

Kentucky Utilities Company
Analysis of Interest Charges
January 31, 2012

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Interest on Long-Term Debt						
Loan Agreement - Pollution Control Bonds						
Mercer County 2000 Series A due 05/01/23 Var%..............	$ 856.48	$ 2,986.44	$ 856.48	$ 2,986.44	$ 22,146.37	$ 41,272.86
Carroll County 2002 Series A due 02/01/32 Var%..............	8,148.97	13,340.26	8,148.97	13,340.26	168,435.98	144,883.90
Carroll County 2002 Series B due 02/01/32 Var%..............	1,026.22	1,532.06	1,026.22	1,532.06	18,984.65	16,615.89
Carroll County 2002 Series C due 10/01/32 Var%..............	6,613.34	28,272.00	6,613.34	28,272.00	232,752.10	700,727.96
Mercer County 2002 Series A due 02/01/32 Var%..............	3,164.21	4,713.70	3,164.21	4,713.70	57,366.67	51,222.20
Muhlenburg County 2002 Series A due 02/01/32 Var%.......	1,026.22	1,528.77	1,026.22	1,528.77	18,605.43	16,612.60
Carroll County 2004 Series A due 10/01/34 Var%..............	3,401.63	12,616.44	3,401.63	12,616.44	94,045.40	153,452.06
Carroll County 2006 Series B due 10/01/34 Var%..............	3,570.49	13,492.60	3,570.49	13,492.60	102,915.69	167,326.03
Carroll County 2007 Series A due 02/01/26 5.75%.............	85,651.04	85,651.04	85,651.04	85,651.04	1,027,812.50	1,027,812.50
Trimble County 2007 Series A due 03/01/37 6.00%............	44,635.00	44,635.00	44,635.00	44,635.00	535,620.00	535,620.00
Carroll County 2008 Series A due 02/01/32 Var%..............	5,217.79	19,433.46	5,217.79	19,433.46	146,975.27	242,277.60
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/01/15 1.625%.........................	338,541.67	338,541.67	338,541.67	338,541.67	4,062,499.99	846,354.18
First Mortgage Bond due 11/01/20 3.250%.........................	1,354,166.67	1,354,166.67	1,354,166.67	1,354,166.67	16,249,999.99	3,385,416.68
First Mortgage Bond due 11/01/40 5.125%.........................	3,203,125.00	3,203,125.00	3,203,125.00	3,203,125.00	38,437,500.00	8,007,812.50
Fidelia/PPL..	-	-	-	-	-	57,918,790.29
Total..	5,059,144.73	5,124,035.11	5,059,144.73	5,124,035.11	61,175,660.04	73,256,197.25
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense..................................	255,443.25	238,782.39	255,443.25	238,782.39	3,139,894.57	804,894.69
Amortization of Loss on Reacquired Debt...............................	50,414.39	50,414.39	50,414.39	50,414.39	604,972.68	604,848.80
Total..	305,857.64	289,196.78	305,857.64	289,196.78	3,744,867.25	1,409,743.49
Other Interest Charges						
Customers' Deposits..	111,377.86	109,153.42	111,377.86	109,153.42	1,365,897.10	1,149,345.87
Other Tax Deficiencies...	-	-	-	-	18,358.75	87,641.07
Interest on DSM Cost Recovery...	(10,858.01)	1,174.41	(10,858.01)	1,174.41	(337.39)	18,991.71
Interest on Debt to Associated Companies..............................	-	4,131.94	-	4,131.94	2,189.41	122,203.56
AFUDC Borrowed Funds..	(756.73)	(458.67)	(756.73)	(458.67)	(13,253.14)	(890,499.71)
Other Interest Expense..	278,099.15	412,285.19	278,099.15	412,285.19	3,843,548.65	2,585,372.71
Total..	377,862.27	526,286.29	377,862.27	526,286.29	5,216,403.38	3,073,055.21
Total Interest...	$ 5,742,864.64	$ 5,939,518.18	$ 5,742,864.64	$ 5,939,518.18	$ 70,136,930.67	$ 77,738,995.95

February 21, 2012

Kentucky Utilities Company
Analysis of Taxes Charged and Accrued
January 31, 2012

Kind of Taxes	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year
Taxes Charged to Accounts 408.1 and 409.1...........				
Property Taxes..	$ 1,740,788.00	$ 1,494,264.00	$ 1,740,788.00	$ 1,494,264.00
Unemployment..	73,723.74	26,447.03	73,723.74	26,447.03
FICA..	599,084.97	600,500.54	599,084.97	600,500.54
Public Service Commission Fee..............................	168,112.85	157,659.37	168,112.85	157,659.37
Federal Income..	9,668,563.87	13,559,920.80	9,668,563.87	13,559,920.80
State Income...	1,763,628.67	2,472,933.88	1,763,628.67	2,472,933.88
Miscellaneous..	13,477.21	10,763.22	13,477.21	10,763.22
Total Charged to Operating Expense..........	14,027,379.31	18,322,488.84	14,027,379.31	18,322,488.84
Taxes Charged to Other Accounts..........................	(4,554,579.56)	506,657.81	(4,554,579.56)	506,657.81
Taxes Accrued on Intercompany Accounts............	(37,372.14)	(602,647.59)	(37,372.14)	(602,647.59)
Total Taxes Charged.................................	$ 9,435,427.61	$ 18,226,499.06	$ 9,435,427.61	$ 18,226,499.06

Analysis of Taxes Accrued - Account 236

Kind of Taxes	Taxes Accrued At Beginning Of Year	Accruals To Date This Year	Payments To Date This Year	Taxes Accrued At End Of Month
Property Taxes..	$ 9,493,201.72	$ 1,740,955.00	$ 10,011.54	$ 11,224,145.18
Unemployment..	70,966.44	67,967.43	21,840.56	117,093.31
FICA..	554,166.20	494,963.31	410,645.88	638,483.63
Federal Income..	-	6,446,025.90	-	6,446,025.90
State Income...	-	332,306.39	-	332,306.39
Kentucky Sales and Use Tax..................................	587,236.42	348,709.58	587,236.42	348,709.58
Miscellaneous..	24,367.21	4,500.00	-	28,867.21
Totals...	$ 10,729,937.99	$ 9,435,427.61	$ 1,029,734.40	$ 19,135,631.20

February 21, 2012

Kentucky Utilities Company
Summary of Utility Plant
January 31, 2012

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant in Service**						
Electric						
Electric Distribution	$ 1,382,494,206.57	$ 1,809,018.91	$ (173,515.32)	$ (79.97)	$ 1,635,423.62	$ 1,384,129,630.19
Electric General Plant	129,755,046.33	688,549.28	-	-	688,549.28	130,443,595.61
Electric Hydro Production	17,134,240.66	-	-	-	-	17,134,240.66
Electric Intangible Plant	54,860,528.56	219,646.31	-	-	219,646.31	55,080,174.87
Electric Other Production	525,899,447.50	-	-	-	-	525,899,447.50
Electric Steam Production	2,659,096,509.86	-	-	-	-	2,659,096,509.86
Electric Transmission	574,848,507.91	2,199,409.41	(185,703.31)	-	2,013,706.10	576,862,214.01
Total 101 Accounts	5,344,088,487.39	4,916,623.91	(359,218.63)	(79.97)	4,557,325.31	5,348,645,812.70
102 **Electric Plant Purchased or Sold**						
Electric						
Electric Steam	483,341.17	-	-	-	-	483,341.17
Total 102001	483,341.17	-	-	-	-	483,341.17
105 **Plant Held for Future Use**						
Electric						
Electric Distribution	792,599.21	-	-	-	-	792,599.21
Electric Steam	-	-	-	-	-	-
Total 105001	792,599.21	-	-	-	-	792,599.21
106 **Completed Construction Not Classified**						
Electric						
Electric Distribution	23,980,094.26	8,316,697.23	-	-	8,316,697.23	32,296,791.49
Electric General Plant	7,738,634.34	138,679.98	-	-	138,679.98	7,877,314.32
Electric Hydro Production	11,505,517.08	117,034.91	-	-	117,034.91	11,622,551.99
Electric Intangible Plant	3,788,766.16	156,719.02	-	-	156,719.02	3,945,485.18
Electric Other Production	1,093,637.80	7,784,467.27	-	-	7,784,467.27	8,878,105.07
Electric Steam Production	967,980,441.51	1,199,831.61	-	-	1,199,831.61	969,180,273.12
Electric Transmission	82,036,721.90	1,881,712.77	-	-	1,881,712.77	83,918,434.67
Total 106 Accounts	1,098,123,813.05	19,595,142.79	-	-	19,595,142.79	1,117,718,955.84
121 **Nonutility Property**						
Common						
Non Utility Property	179,120.94	-	-	-	-	179,120.94
Total 121001	179,120.94	-	-	-	-	179,120.94
107 **Construction Work In Progress**						
Electric						
Electric	339,711,431.64	(3,889,473.78)	-	-	(3,889,473.78)	335,821,957.86
Total 107001	339,711,431.64	(3,889,473.78)	-	-	(3,889,473.78)	335,821,957.86
Total Plant (Non-CWIP)	6,443,667,361.76	24,511,766.70	(359,218.63)	(79.97)	24,152,468.10	6,467,819,829.86
Total Plant + CWIP	6,783,378,793.40	20,622,292.92	(359,218.63)	(79.97)	20,262,994.32	6,803,641,787.72
Total Plant + CWIP - Nonutility (BS)	$ 6,783,199,672.46	$ 20,622,292.92	$ (359,218.63)	$ (79.97)	$ 20,262,994.32	$ 6,803,462,666.78

February 21, 2012

Kentucky Utilities Company
Summary of Utility Plant - Reserve for Depreciation of Utility Plant
January 31, 2012

	Beginning Balance	Accruals	Retirements	Transfers/ Adjustments	ARO Settlements	RWIP Transfers Out	Cost of Removal	Salvage	Other Credits	Ending Balance
Life Reserve										
Electric Distribution.....................................	$ (411,056,321.05)	$ (2,366,262.98)	$ 173,515.32	$ -	$ -	$ -	$ -	$ -	$ -	$ (413,249,068.71)
Electric Distribution - ARO..........................	(6,765.54)	(2,525.87)	-	(307.57)	-	-	-	-	-	(9,598.98)
Electric General Plant..................................	(54,490,775.21)	(566,002.95)	-	-	-	-	-	-	-	(55,056,778.16)
Electric Hydro Production............................	(7,872,943.76)	(16,933.33)	-	-	-	-	-	-	-	(7,889,877.09)
Electric Hydro Production - ARO................	(1,094.53)	(81.08)	-	-	-	-	-	-	-	(1,175.61)
Electric Other Production.............................	(175,058,471.14)	(1,409,788.03)	-	-	-	-	-	-	-	(176,468,259.17)
Electric Other Production - ARO.................	(763.60)	(56.57)	-	-	-	-	-	-	-	(820.17)
Electric Steam Production............................	(1,146,202,987.01)	(7,666,873.89)	-	-	-	-	-	-	-	(1,153,869,860.90)
Electric Steam Production - ARO................	(3,512,619.50)	(256,512.17)	-	-	-	-	-	-	-	(3,769,131.67)
Electric Transmission...................................	(217,974,783.91)	(801,344.64)	185,703.31	-	-	-	-	-	-	(218,590,425.24)
Electric Transmission - ARO.......................	(2,671.85)	(1,363.17)	-	-	-	-	-	-	-	(4,035.02)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(2,016,180,197.10)	(13,087,744.68)	359,218.63	(307.57)	-	-	-	-	-	(2,028,909,030.72)
Cost of Removal										
Electric Distribution.....................................	(199,658,860.39)	(696,538.14)	-	-	-	-	116,720.14	-	-	(200,238,678.39)
Electric General Plant..................................	250,582.68	(4,372.54)	-	-	-	-	-	-	-	246,210.14
Electric Hydro Production............................	(350,001.10)	(439.50)	-	-	-	-	-	-	-	(350,440.60)
Electric Other Production.............................	(3,572,221.61)	(75,595.01)	-	-	-	-	-	-	-	(3,647,816.62)
Electric Steam Production............................	(136,295,560.94)	(2,178,253.94)	-	-	-	-	-	-	-	(138,473,814.88)
Electric Transmission...................................	(138,104,734.27)	(242,672.00)	-	-	-	-	621,910.37	-	-	(137,725,495.90)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(477,730,795.63)	(3,197,871.13)	-	-	-	-	738,630.51	-	-	(480,190,036.25)
Salvage										
Electric Distribution.....................................	49,559,394.32	170,092.12	-	-	-	-	-	(35,077.04)	-	49,694,409.40
Electric General Plant..................................	137,079.64	-	-	-	-	-	-	-	-	137,079.64
Electric Hydro Production............................	46,518.69	-	-	-	-	-	-	-	-	46,518.69
Electric Other Production.............................	618,891.61	-	-	-	-	-	-	-	-	618,891.61
Electric Steam Production............................	24,235,511.41	410,616.64	-	-	-	-	-	-	-	24,646,128.05
Electric Transmission...................................	23,638,002.34	56,235.77	-	-	-	-	-	(15,622.77)	-	23,678,615.34
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	98,235,398.01	636,944.53	-	-	-	-	-	(50,699.81)	-	98,821,642.73
Total Reserves										
Electric Distribution.....................................	(561,155,787.12)	(2,892,709.00)	173,515.32	-	-	-	116,720.14	(35,077.04)	-	(563,793,337.70)
Electric Distribution - ARO..........................	(6,765.54)	(2,525.87)	-	(307.57)	-	-	-	-	-	(9,598.98)
Electric General Plant..................................	(54,103,112.89)	(570,375.49)	-	-	-	-	-	-	-	(54,673,488.38)
Electric Hydro Production............................	(8,176,426.17)	(17,372.83)	-	-	-	-	-	-	-	(8,193,799.00)
Electric Hydro Production - ARO................	(1,094.53)	(81.08)	-	-	-	-	-	-	-	(1,175.61)
Electric Other Production.............................	(178,011,801.14)	(1,485,383.04)	-	-	-	-	-	-	-	(179,497,184.18)
Electric Other Production - ARO.................	(763.60)	(56.57)	-	-	-	-	-	-	-	(820.17)
Electric Steam Production............................	(1,258,263,036.54)	(9,434,511.19)	-	-	-	-	-	-	-	(1,267,697,547.73)
Electric Steam Production - ARO................	(3,512,619.50)	(256,512.17)	-	-	-	-	-	-	-	(3,769,131.67)
Electric Transmission...................................	(332,441,515.84)	(987,780.87)	185,703.31	-	-	-	621,910.37	(15,622.77)	-	(332,637,305.80)
Electric Transmission - ARO.......................	(2,671.85)	(1,363.17)	-	-	-	-	-	-	-	(4,035.02)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(2,395,675,594.72)	(15,648,671.28)	359,218.63	(307.57)	-	-	738,630.51	(50,699.81)	-	(2,410,277,424.24)
Retirement Work in Process										
Electric...	18,384,586.20	-	-	-	-	(687,930.70)	677,931.00	(26,383.96)	(71,603.07)	18,276,599.47
	18,384,586.20	-	-	-	-	(687,930.70)	677,931.00	(26,383.96)	(71,603.07)	18,276,599.47
YTD ACTIVITY	(2,377,291,008.52)	(15,648,671.28)	359,218.63	(307.57)	-	(687,930.70)	1,416,561.51	(77,083.77)	(71,603.07)	(2,392,000,824.77)
Amortization										
Electric...	(17,746,764.31)	(644,247.84)	-	-	-	-	-	-	-	(18,391,012.15)
	(17,746,764.31)	(644,247.84)	-	-	-	-	-	-	-	(18,391,012.15)
Depreciation & Amortization Total										
Depreciation & Amortization Total...............	(2,395,037,772.83)	(16,292,919.12)	359,218.63	(307.57)	-	(687,930.70)	1,416,561.51	(77,083.77)	(71,603.07)	(2,410,391,836.92)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)...............	$ 4,388,161,899.63									$ 4,393,070,829.86

February 21, 2012

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of January 31, 2012

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues....................................	$ 137,529,300.71	$ -	$ 137,529,300.71
Rate Refunds..	-	-	-
Total Operating Revenues....................................	137,529,300.71	-	137,529,300.71
Fuel for Electric Generation......................................	45,946,560.87	-	45,946,560.87
Power Purchased..	10,857,643.25	-	10,857,643.25
Other Operation Expenses..	19,267,877.49	-	19,267,877.49
Maintenance...	7,725,599.84	-	7,725,599.84
Depreciation...	15,614,241.03	-	15,614,241.03
Amortization Expense..	644,247.84	-	644,247.84
Regulatory Credits..	(519,027.69)	-	(519,027.69)
Taxes			
Federal Income...	9,668,563.87	-	9,668,563.87
State Income...	1,763,628.67	-	1,763,628.67
Deferred Federal Income - Net..............................	108,274.01	(22,475.59)	85,798.42
Deferred State Income - Net..................................	0.01	(4,098.89)	(4,098.88)
Property and Other...	2,595,186.77	-	2,595,186.77
Loss (Gain) from Disposition of Allowances...........	-	-	-
Accretion Expense..	260,128.50	-	260,128.50
Total Operating Expenses.....................................	113,932,924.46	(26,574.48)	113,906,349.98
Net Operating Income...	23,596,376.25	26,574.48	23,622,950.73
Other Income Less Deductions			
Amortization of Investment Tax Credit.............	233,343.00	-	233,343.00
Other Income Less Deductions...........................	(216,310.90)	(73,840.35)	(290,151.25)
AFUDC - Equity...	2,921.46	-	2,921.46
Total Other Income Less Deductions.....................	19,953.56	(73,840.35)	(53,886.79)
Income Before Interest Charges.............................	23,616,329.81	(47,265.87)	23,569,063.94
Interest on Long-Term Debt....................................	5,059,144.73	(5,525.49)	5,053,619.24
Amortization of Debt Expense - Net.........................	305,857.64	-	305,857.64
Other Interest Expenses...	378,619.00	-	378,619.00
AFUDC - Borrowed Funds......................................	(756.73)	-	(756.73)
Total Interest Charges..	5,742,864.64	(5,525.49)	5,737,339.15
Net Income..	$ 17,873,465.17	$ (41,740.38)	$ 17,831,724.79

February 21, 2012

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of January 31, 2012

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 137,529,300.71	$ -	$ 137,529,300.71
Rate Refunds	-	-	-
Total Operating Revenues	137,529,300.71	-	137,529,300.71
Fuel for Electric Generation	45,946,560.87	-	45,946,560.87
Power Purchased	10,857,643.25	-	10,857,643.25
Other Operation Expenses	19,267,877.49	-	19,267,877.49
Maintenance	7,725,599.84	-	7,725,599.84
Depreciation	15,614,241.03	-	15,614,241.03
Amortization Expense	644,247.84	-	644,247.84
Regulatory Credits	(519,027.69)	-	(519,027.69)
Taxes			
Federal Income	9,668,563.87	-	9,668,563.87
State Income	1,763,628.67	-	1,763,628.67
Deferred Federal Income - Net	108,274.01	(22,475.59)	85,798.42
Deferred State Income - Net	0.01	(4,098.89)	(4,098.88)
Property and Other	2,595,186.77	-	2,595,186.77
Loss (Gain) from Disposition of Allowances	-	-	-
Accretion Expense	260,128.50	-	260,128.50
Total Operating Expenses	113,932,924.46	(26,574.48)	113,906,349.98
Net Operating Income	23,596,376.25	26,574.48	23,622,950.73
Other Income Less Deductions			
Amortization of Investment Tax Credit	233,343.00	-	233,343.00
Other Income Less Deductions	(216,310.90)	(73,840.35)	(290,151.25)
AFUDC - Equity	2,921.46	-	2,921.46
Total Other Income Less Deductions	19,953.56	(73,840.35)	(53,886.79)
Income Before Interest Charges	23,616,329.81	(47,265.87)	23,569,063.94
Interest on Long-Term Debt	5,059,144.73	(5,525.49)	5,053,619.24
Amortization of Debt Expense - Net	305,857.64	-	305,857.64
Other Interest Expenses	378,619.00	-	378,619.00
AFUDC - Borrowed Funds	(756.73)	-	(756.73)
Total Interest Charges	5,742,864.64	(5,525.49)	5,737,339.15
Net Income	$ 17,873,465.17	$ (41,740.38)	$ 17,831,724.79

February 21, 2012

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of January 31, 2012

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,490,663,791.10	$ 16,355,594.75	$ (1,402,366,687.37)	$ (15,274,584.64)	$ 88,297,103.73	$ 1,081,010.11
Add						
Net Income for Period..	17,873,465.17	-	(41,740.38)	-	17,831,724.79	-
Deductions:						
Common Dividends						
Common Stock Without Par Value..................	-	-	-	-	-	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	451,598.00	(451,598.00)	73,840.35	(73,840.35)	525,438.35	(525,438.35)
Balance at End of Period	$ 1,508,988,854.27	$ 15,903,996.75	$ (1,402,334,587.40)	$ (15,348,424.99)	$ 106,654,266.87	$ 555,571.76
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings................		15,903,996.75		(15,348,424.99)		555,571.76
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.........................		$ 6,186,654.74		$ (5,970,537.32)		$ 216,117.41

February 21, 2012

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of January 31, 2012

Retained Earnings and Undistributed Earnings	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Combined	
	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,490,663,791.10	$ 16,355,594.75	$ (1,402,366,687.37)	$ (15,274,584.64)	$ 88,297,103.73	$ 1,081,010.11
Add						
Net Income for Period ……………………………	17,873,465.17	-	(41,740.38)	-	17,831,724.79	-
Deductions:						
Common Dividends						
Common Stock Without Par Value...................	-	-	-	-	-	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc…………………………..…………	451,598.00	(451,598.00)	73,840.35	(73,840.35)	525,438.35	(525,438.35)
Balance at End of Period …...…………………………	$ 1,508,988,854.27	$ 15,903,996.75	$ (1,402,334,587.40)	$ (15,348,424.99)	$ 106,654,266.87	$ 555,571.76
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings…………		15,903,996.75		(15,348,424.99)		555,571.76
Statutory Tax Rate…...…………………………………		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary…...…………….		$ 6,186,654.74		$ (5,970,537.32)		$ 216,117.41

February 21, 2012

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of January 31, 2012

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,464,645,446.43	$ 14,298,520.75	$ (1,403,535,850.50)	$ (14,314,660.10)	$ 61,109,595.93	$ (16,139.35)
Add						
Net Income for Period...	169,448,883.84	-	167,498.21	-	169,616,382.05	-
Deductions:						
Common Dividends						
Common Stock Without Par Value...................	(123,500,000.00)	-	-	-	(123,500,000.00)	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc..	(1,605,476.00)	1,605,476.00	1,033,764.89	(1,033,764.89)	(571,711.11)	571,711.11
Balance at End of Period	$ 1,508,988,854.27	$ 15,903,996.75	$ (1,402,334,587.40)	$ (15,348,424.99)	$ 106,654,266.87	$ 555,571.76

Deferred Taxes Related to Undistributed Subsidiary Earnings

Balance of Undistributed Subsidiary Earnings................	15,903,996.75	(15,348,424.99)	555,571.76
Statutory Tax Rate...	38.9%	38.9%	38.9%
Deferred Taxes on Equity in Subsidiary..........................	$ 6,186,654.74	$ (5,970,537.32)	$ 216,117.41

Combined Balance of Retained Earnings	12 MONTHS 1/31/2012	12 MONTHS 1/31/2011
Retained Earnings at Beginning of Period.......................	$ 61,093,456.58	$ 1,342,284,237.05
Net Income for Period	169,616,382.05	187,133,606.13
FIN 48 Adjustment...	-	-
Subtotal..	230,709,838.63	1,529,417,843.18
Deduct		
Purchase Accounting Adjustment...............................	-	1,404,083,566.85
Dividends on Common Stock.....................................	123,500,000.00	50,000,000.00
Retained Earnings at End of Period.................................	$ 107,209,838.63	$ 75,334,276.33

February 21, 2012

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of January 31, 2012

Assets		Without Purchase Accounting		Purchase Accounting Adjustments		Total
Utility Plant						
Utility Plant at Original Cost....................................	$	6,803,462,666.78	$	-	$	6,803,462,666.78
Less Reserves for Depreciation and Amortization.....		2,410,391,836.92		-		2,410,391,836.92
Total..		4,393,070,829.86		-		4,393,070,829.86
Investments						
Electric Energy, Inc...		7,808,493.55		16,614,077.76		24,422,571.31
Ohio Valley Electric Corporation.............................		250,000.00		-		250,000.00
Nonutility Property - Less Reserve...........................		179,120.94		-		179,120.94
Special Funds...		-		-		-
Total..		8,237,614.49		16,614,077.76		24,851,692.25
Current and Accrued Assets						
Cash..		34,865,584.78		-		34,865,584.78
Special Deposits..		45,500.00		-		45,500.00
Temporary Cash Investments.................................		43,949.50		-		43,949.50
Accounts Receivable-Less Reserve........................		170,930,926.96		-		170,930,926.96
Accounts Receivable from Assoc Companies..........		37,600.00		-		37,600.00
Materials & Supplies-At Average Cost						
Fuel..		87,935,980.78		-		87,935,980.78
Plant Materials & Operating Supplies..................		34,252,319.17		-		34,252,319.17
Stores Expense..		10,051,772.10		-		10,051,772.10
Allowance Inventory..		437,931.35		-		437,931.35
Prepayments..		6,716,116.70		-		6,716,116.70
Miscellaneous Current & Accrued Assets..............		-		-		-
Total..		345,317,681.34		-		345,317,681.34
Deferred Debits and Other						
Unamortized Debt Expense......................................		21,398,407.22		(4,391,696.46)		17,006,710.76
Unamortized Loss on Bonds....................................		11,724,702.98		-		11,724,702.98
Accumulated Deferred Income Taxes.......................		86,638,419.05		57,520,733.36		144,159,152.41
Deferred Regulatory Assets.....................................		270,161,197.40		10,864,904.34		281,026,101.74
Other Deferred Debits..		45,344,944.06		137,881,776.30		183,226,720.36
Goodwill..		-		607,404,368.23		607,404,368.23
Total..		435,267,670.71		809,280,085.77		1,244,547,756.48
Total Assets..	$	5,181,893,796.40	$	825,894,163.53	$	6,007,787,959.93

February 21, 2012

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of January 31, 2012

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Proprietary Capital			
Common Stock..	$ 308,139,977.56	$ -	$ 308,139,977.56
Less: Common Stock Expense....................................	321,288.87	-	321,288.87
Paid-In Capital..	315,858,083.00	2,032,588,750.94	2,348,446,833.94
Other Comprehensive Income....................................	(5,738,086.25)	1,990,823.26	(3,747,262.99)
Retained Earnings...	1,508,988,854.27	(1,402,334,587.40)	106,654,266.87
Unappropriated Undistributed Subsidiary Earnings....	15,903,996.75	(15,348,424.99)	555,571.76
Total Proprietary Capital...	2,142,831,536.46	616,896,561.81	2,759,728,098.27
Pollution Control Bonds - Net of Reacquired Bonds...	350,779,405.00	1,078,572.64	351,857,977.64
First Mortgage Bonds..	1,489,865,093.75	-	1,489,865,093.75
Total Long-Term Debt...	1,840,644,498.75	1,078,572.64	1,841,723,071.39
Total Capitalization..	3,983,476,035.21	617,975,134.45	4,601,451,169.66
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Accounts Payable...	102,021,113.92	-	102,021,113.92
Accounts Payable to Associated Companies................	30,032,920.51	-	30,032,920.51
Customer Deposits...	22,803,107.92	-	22,803,107.92
Taxes Accrued..	19,135,631.20	-	19,135,631.20
Interest Accrued...	15,717,741.67	-	15,717,741.67
Dividends Declared..	-	-	-
Miscellaneous Current and Accrued Liabilities...........	23,113,050.25	-	23,113,050.25
Total..	212,823,565.47	-	212,823,565.47
Deferred Credits and Other			
Accumulated Deferred Income Taxes..........................	557,374,045.20	63,564,044.90	620,938,090.10
Investment Tax Credit..	101,174,425.32	-	101,174,425.32
Regulatory Liabilities..	111,812,562.27	137,881,776.30	249,694,338.57
Customer Advances for Construction..........................	3,149,042.71	-	3,149,042.71
Asset Retirement Obligations......................................	62,049,630.71	-	62,049,630.71
Other Deferred Credits...	11,537,934.99	6,473,207.88	18,011,142.87
Miscellaneous Long-Term Liabilities..........................	2,695,347.71	-	2,695,347.71
Accum Provision for Postretirement Benefits.............	135,801,206.81	-	135,801,206.81
Total..	985,594,195.72	207,919,029.08	1,193,513,224.80
Total Liabilities and Stockholders' Equity.........................	$ 5,181,893,796.40	$ 825,894,163.53	$ 6,007,787,959.93

February 21, 2012

KENTUCKY UTILITIES COMPANY

Financial Reports

December 31, 2011

Index
Financial and Operating Reports

Kentucky Utilities Company
December 31, 2011

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2011 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows, unless otherwise noted.

Kentucky Utilities Company
Comparative Statement of Income
December 31, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 129,764,309.79	$ 158,929,990.63	$ (29,165,680.84)	(18.35)
Rate Refunds	-	-	-	-
Total Operating Revenues	129,764,309.79	158,929,990.63	(29,165,680.84)	(18.35)
Fuel for Electric Generation	41,582,961.98	48,894,187.86	(7,311,225.88)	(14.95)
Power Purchased	11,162,281.23	15,924,769.36	(4,762,488.13)	(29.91)
Other Operation Expenses	20,482,363.67	21,827,867.42	(1,345,503.75)	(6.16)
Maintenance	8,842,126.53	13,030,961.33	(4,188,834.80)	(32.15)
Depreciation	15,482,322.89	12,429,803.77	3,052,519.12	24.56
Amortization Expense	649,881.53	555,892.43	93,989.10	16.91
Regulatory Credits	(512,739.19)	(465,879.58)	(46,859.61)	(10.06)
Taxes				
Federal Income	(18,240,147.68)	7,587,155.50	(25,827,303.18)	(340.41)
State Income	(2,662,895.90)	1,556,296.77	(4,219,192.67)	(271.10)
Deferred Federal Income - Net	26,184,610.91	3,968,292.08	22,216,318.83	559.85
Deferred State Income - Net	3,544,807.19	556,106.58	2,988,700.61	537.43
Property and Other	2,507,737.24	1,867,031.58	640,705.66	34.32
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	-	(12,726.93)	12,726.93	100.00
Accretion Expense	252,815.66	223,681.89	29,133.77	13.02
Total Operating Expenses	109,276,126.06	127,943,440.06	(18,667,314.00)	(14.59)
Net Operating Income	20,488,183.73	30,986,550.57	(10,498,366.84)	(33.88)
Other Income Less Deductions				
Amortization of Investment Tax Credit	233,339.00	5,925.00	227,414.00	3,838.21
Other Income Less Deductions	689,453.50	(3,206.90)	692,660.40	21,599.06
AFUDC - Equity	1,895.10	104,261.17	(102,366.07)	(98.18)
Total Other Income Less Deductions	924,687.60	106,979.27	817,708.33	764.36
Income Before Interest Charges	21,412,871.33	31,093,529.84	(9,680,658.51)	(31.13)
Interest on Long-Term Debt	5,071,128.05	5,140,905.49	(69,777.44)	(1.36)
Amortization of Debt Expense - Net	305,857.64	289,078.00	16,779.64	5.80
Other Interest Expenses	375,617.75	598,095.36	(222,477.61)	(37.20)
AFUDC - Borrowed Funds	(575.60)	(82,702.68)	82,127.08	99.30
Total Interest Charges	5,752,027.84	5,945,376.17	(193,348.33)	(3.25)
Net Income	$ 15,660,843.49	$ 25,148,153.67	$ (9,487,310.18)	(37.73)

January 26, 2012

Kentucky Utilities Company
Comparative Statement of Income
December 31, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues.....................................	$ 1,547,516,986.10	$ 1,512,342,095.92	$ 35,174,890.18	2.33
Rate Refunds..	-	(632,383.92)	632,383.92	100.00
Total Operating Revenues......................................	1,547,516,986.10	1,511,709,712.00	35,807,274.10	2.37
Fuel for Electric Generation......................................	522,648,642.11	496,084,188.13	26,564,453.98	5.35
Power Purchased...	109,114,947.74	174,621,937.27	(65,506,989.53)	(37.51)
Other Operation Expenses..	233,508,690.94	216,647,227.77	16,861,463.17	7.78
Maintenance..	116,303,368.69	107,813,984.80	8,489,383.89	7.87
Depreciation..	181,926,788.12	139,282,040.69	42,644,747.43	30.62
Amortization Expense...	7,263,444.41	6,603,463.92	659,980.49	9.99
Regulatory Credits...	(5,855,639.93)	(5,149,557.35)	(706,082.58)	(13.71)
Taxes				
Federal Income...	(6,941,452.11)	61,659,449.28	(68,600,901.39)	(111.26)
State Income...	4,455,179.15	12,756,392.51	(8,301,213.36)	(65.07)
Deferred Federal Income - Net...............................	101,588,779.03	22,275,451.75	79,313,327.28	356.06
Deferred State Income - Net...................................	9,974,459.79	3,311,038.18	6,663,421.61	201.25
Property and Other...	28,115,766.46	19,893,478.97	8,222,287.49	41.33
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances...........	(3,293.39)	(56,750.74)	53,457.35	94.20
Accretion Expense..	2,827,116.86	3,498,904.94	(671,788.08)	(19.20)
Total Operating Expenses......................................	1,304,926,797.87	1,259,241,250.12	45,685,547.75	3.63
Net Operating Income...	242,590,188.23	252,468,461.88	(9,878,273.65)	(3.91)
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	2,686,401.00	71,100.00	2,615,301.00	3,678.34
Other Income Less Deductions...........................	1,749,729.68	1,057,913.92	691,815.76	65.39
AFUDC - Equity...	42,661.58	521,152.04	(478,490.46)	(91.81)
Total Other Income Less Deductions......................	4,478,792.26	1,650,165.96	2,828,626.30	171.41
Income Before Interest Charges.............................	247,068,980.49	254,118,627.84	(7,049,647.35)	(2.77)
Interest on Long-Term Debt......................................	61,240,550.42	74,444,442.22	(13,203,891.80)	(17.74)
Amortization of Debt Expense - Net.........................	3,728,206.39	1,188,941.91	2,539,264.48	213.57
Other Interest Expenses..	5,377,782.48	3,959,422.97	1,418,359.51	35.82
AFUDC - Borrowed Funds.......................................	(12,955.08)	(968,596.93)	955,641.85	98.66
Total Interest Charges..	70,333,584.21	78,624,210.17	(8,290,625.96)	(10.54)
Net Income..	$ 176,735,396.28	$ 175,494,417.67	$ 1,240,978.61	0.71

January 26, 2012

Kentucky Utilities Company
Comparative Statement of Income
December 31, 2011

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 1,547,516,986.10	$ 1,512,342,095.92	$ 35,174,890.18	2.33
Rate Refunds	-	(632,383.92)	632,383.92	100.00
Total Operating Revenues	1,547,516,986.10	1,511,709,712.00	35,807,274.10	2.37
Fuel for Electric Generation	522,648,642.11	496,084,188.13	26,564,453.98	5.35
Power Purchased	109,114,947.74	174,621,937.27	(65,506,989.53)	(37.51)
Other Operation Expenses	233,508,690.94	216,647,227.77	16,861,463.17	7.78
Maintenance	116,303,368.69	107,813,984.80	8,489,383.89	7.87
Depreciation	181,926,788.12	139,282,040.69	42,644,747.43	30.62
Amortization Expense	7,263,444.41	6,603,463.92	659,980.49	9.99
Regulatory Credits	(5,855,639.93)	(5,149,557.35)	(706,082.58)	(13.71)
Taxes				
Federal Income	(6,941,452.11)	61,659,449.28	(68,600,901.39)	(111.26)
State Income	4,455,179.15	12,756,392.51	(8,301,213.36)	(65.07)
Deferred Federal Income - Net	101,588,779.03	22,275,451.75	79,313,327.28	356.06
Deferred State Income - Net	9,974,459.79	3,311,038.18	6,663,421.61	201.25
Property and Other	28,115,766.46	19,893,478.97	8,222,287.49	41.33
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	(3,293.39)	(56,750.74)	53,457.35	94.20
Accretion Expense	2,827,116.86	3,498,904.94	(671,788.08)	(19.20)
Total Operating Expenses	1,304,926,797.87	1,259,241,250.12	45,685,547.75	3.63
Net Operating Income	242,590,188.23	252,468,461.88	(9,878,273.65)	(3.91)
Other Income Less Deductions				
Amortization of Investment Tax Credit	2,686,401.00	71,100.00	2,615,301.00	3,678.34
Other Income Less Deductions	1,749,729.68	1,057,913.92	691,815.76	65.39
AFUDC - Equity	42,661.58	521,152.04	(478,490.46)	(91.81)
Total Other Income Less Deductions	4,478,792.26	1,650,165.96	2,828,626.30	171.41
Income Before Interest Charges	247,068,980.49	254,118,627.84	(7,049,647.35)	(2.77)
Interest on Long-Term Debt	61,240,550.42	74,444,442.22	(13,203,891.80)	(17.74)
Amortization of Debt Expense - Net	3,728,206.39	1,188,941.91	2,539,264.48	213.57
Other Interest Expenses	5,377,782.48	3,959,422.97	1,418,359.51	35.82
AFUDC - Borrowed Funds	(12,955.08)	(968,596.93)	955,641.85	98.66
Total Interest Charges	70,333,584.21	78,624,210.17	(8,290,625.96)	(10.54)
Net Income	$ 176,735,396.28	$ 175,494,417.67	$ 1,240,978.61	0.71

January 26, 2012

Kentucky Utilities Company
Analysis of Retained Earnings
December 31, 2011

Retained Earnings and Undistributed Earnings	Current Month: Total Retained Earnings	Current Month: Undistributed Subsidiary Earnings	Year to Date: Total Retained Earnings	Year to Date: Undistributed Subsidiary Earnings	Year Ended Current Month: Total Retained Earnings	Year Ended Current Month: Undistributed Subsidiary Earnings
Balance at Beginning of Period..	$ 1,475,266,420.61	$ 16,092,121.75	$ 1,439,351,593.82	$ 14,432,395.75	$ 1,439,351,593.82	$ 14,432,395.75
Add:						
Net Income for Period..	15,660,843.49	-	176,735,396.28	-	176,735,396.28	-
Deduct:						
Common Dividends						
Common Stock Without Par Value	-	-	(123,500,000.00)	-	(123,500,000.00)	-
EE Inc..	(263,473.00)	263,473.00	(1,923,199.00)	1,923,199.00	(1,923,199.00)	1,923,199.00
Balance at End of Period...	$ 1,490,663,791.10	$ 16,355,594.75	$ 1,490,663,791.10	$ 16,355,594.75	$ 1,490,663,791.10	$ 16,355,594.75
Deferred Taxes Related to Undistributed Subsidiary Earnings		-		-		-
Balance of Undistributed Subsidiary Earnings.............................		16,355,594.75		16,355,594.75		16,355,594.75
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.......................................		$ 6,362,326.36		$ 6,362,326.36		$ 6,362,326.36

January 26, 2012

Kentucky Utilities Company
Comparative Balance Sheets as of December 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,783,199,672.46	$ 6,496,781,295.39
Less: Reserves for Depreciation and Amortization	2,395,037,772.83	2,261,926,782.36
Total	4,388,161,899.63	4,234,854,513.03
Investments		
Electric Energy, Inc	13,628,644.55	12,465,221.55
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	179,120.94	179,120.94
Total	14,057,765.49	12,894,342.49
Current and Accrued Assets		
Cash	31,096,140.42	3,132,599.79
Special Deposits	45,500.00	418,600.30
Temporary Cash Investments	43,674.49	200,847.07
Accounts Receivable-Less Reserve	164,311,372.23	198,513,561.39
Accounts Receivable from Associated Companies	39,615.59	11,996,433.15
Materials and Supplies-At Average Cost		
Fuel	96,745,428.76	94,898,528.15
Plant Materials and Operating Supplies	34,036,932.19	32,560,243.26
Stores Expense	9,914,010.27	8,854,899.43
Emission Allowances	450,462.32	566,579.00
Prepayments	7,285,320.31	8,173,724.00
Miscellaneous Current and Accrued Assets	-	20,501.20
Total	343,968,456.58	359,336,516.74
Deferred Debits and Other		
Unamortized Debt Expense	21,600,912.97	21,213,642.72
Unamortized Loss on Bonds	11,775,117.37	12,380,090.05
Accumulated Deferred Income Taxes	86,746,693.05	34,511,064.10
Deferred Regulatory Assets	268,828,295.77	208,403,355.44
Other Deferred Debits	45,192,019.67	42,753,151.34
Total	434,143,038.83	319,261,303.65
Total Assets	$ 5,180,331,160.53	$ 4,926,346,675.91

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	315,858,083.00	315,858,083.00
Other Comprehensive Income	(2,457,900.37)	(1,993,677.24)
Retained Earnings	1,490,663,791.10	1,439,351,593.82
Unappropriated Undistributed Subsidiary Earnings	16,355,594.75	14,432,395.75
Total Proprietary Capital	2,128,238,257.17	2,075,467,084.02
Pollution Control Bonds	350,779,405.00	350,779,405.00
First Mortgage Bonds	1,489,812,156.25	1,489,176,906.25
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,840,591,561.25	1,839,956,311.25
Total Capitalization	3,968,829,818.42	3,915,423,395.27
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	10,434,000.00
Accounts Payable	119,658,898.66	76,307,786.67
Accounts Payable to Associated Companies	33,178,775.21	45,351,361.74
Customer Deposits	22,862,411.92	22,839,133.25
Taxes Accrued	10,729,937.99	24,614,782.98
Interest Accrued	10,619,839.16	8,149,642.02
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	19,177,240.61	19,512,357.41
Total	216,227,103.55	207,209,064.07
Deferred Credits and Other		
Accumulated Deferred Income Taxes	559,462,412.30	396,607,180.67
Investment Tax Credit	101,407,768.32	104,094,169.32
Regulatory Liabilities	108,313,656.21	55,112,630.40
Customer Advances for Construction	3,155,939.30	2,869,273.92
Asset Retirement Obligations	61,789,582.18	53,981,306.41
Other Deferred Credits	6,945,601.15	8,491,442.40
Miscellaneous Long-Term Liabilities	2,695,347.71	2,423,615.65
Accum Provision for Postretirement Benefits	151,503,931.39	180,134,597.80
Total	995,274,238.56	803,714,216.57
Total Liabilities and Stockholders Equity	$ 5,180,331,160.53	$ 4,926,346,675.91

January 26, 2012

Kentucky Utilities Company
Statement of Capitalization and Short-Term Debt
December 31, 2011

	Authorized Shares	Issued and Outstanding Shares	Issued and Outstanding Amount	Percent of Total Capital
Proprietary Capital				
Common Stock - Without Par..	80,000,000	37,817,878	$ 308,139,977.56	
Less: Common Stock Expense..			321,288.87	
Paid-In Capital..			315,858,083.00	
Other Comprehensive Income..			(2,457,900.37)	
Retained Earnings..			1,490,663,791.10	
Unappropriated Undistributed Subsidiary Earnings.............			16,355,594.75	
Total Proprietary Capital...			2,128,238,257.17	53.62
Long-Term Debt				
Pollution Control Bonds				
Mercer County 2000 Series A due 05/01/23 Var%...........			12,900,000.00	
Carroll County 2002 Series A due 02/01/32 Var%...........			20,930,000.00	
Carroll County 2002 Series B due 02/01/32 Var%...........			2,400,000.00	
Carroll County 2002 Series C due 10/01/32 Var%...........			96,000,000.00	
Mercer County 2002 Series A due 02/01/32 Var%...........			7,400,000.00	
Muhlenburg County 2002 Series A due 02/01/32 Var%...			2,400,000.00	
Carroll County 2004 Series A due 10/01/34 Var%...........			50,000,000.00	
Carroll County 2006 Series B due 10/01/34 Var%...........			54,000,000.00	
Carroll County 2007 Series A due 02/01/26 5.75%..........			17,875,000.00	
Trimble County 2007 Series A due 03/01/37 6.00%.........			8,927,000.00	
Carroll County 2008 Series A due 02/01/32 Var%...........			77,947,405.00	
Total Pollution Control Bonds..			350,779,405.00	8.84
First Mortgage Bonds				
First Mortgage Bond due 11/01/15 1.625%........................			250,000,000.00	
First Mortgage Bond due 11/01/20 3.250%.......................			500,000,000.00	
First Mortgage Bond due 11/01/40 5.125%.......................			750,000,000.00	
Total First Mortgage Bonds..			1,500,000,000.00	37.79
Less: First Mortgage Bonds Debt Discount				
First Mortgage Bond due 11/01/15 1.625%........................			(678,125.02)	
First Mortgage Bond due 11/01/20 3.250%.......................			(1,677,375.00)	
First Mortgage Bond due 11/01/40 5.125%.......................			(7,832,343.73)	
			(10,187,843.75)	(0.25)
Total First Mortgage Bonds - Net of Debt Discount............			1,489,812,156.25	37.54
Total Capitalization..			$ 3,968,829,818.42	100.00

January 26, 2012

Kentucky Utilities Company
Summary Trial Balance
December 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 6,783,199,672.46	$ 6,783,199,672.46
Reserves for Depreciation and Amortization		(2,395,037,772.83)
Depreciation of Plant	(2,377,291,008.52)	
Amortization of Plant	(17,746,764.31)	
Investments		14,057,765.49
Electric Energy, Inc	13,628,644.55	
Ohio Valley Electric Corporation	250,000.00	
Nonutility Property Reserve	179,120.94	
Cash	31,096,140.42	31,096,140.42
Special Deposits		45,500.00
Restricted Cash	45,500.00	
Temporary Cash Investments	43,674.49	43,674.49
Accounts Receivable - Less Reserve		164,311,372.23
Unbilled Revenues	81,180,950.18	
Customers - Active	70,259,825.37	
Income Tax Receivable - Federal	3,235,053.66	
IMPA	2,363,104.25	
IMEA	2,232,737.63	
Income Tax Receivable - State	1,433,383.93	
Transmission Sales	1,100,438.21	
Damage Claims	288,498.28	
Sundry Accounts Receivable	5,078.16	
Other	4,216,614.32	
Reserves for Uncollectible Accounts		
Utility Customers		
Reserve	(1,897,050.00)	
A/R Miscellaneous	(81,529.63)	
LEM Reserve	(25,732.13)	
Accounts Receivable from Associated Companies		39,615.59
LG&E and KU Services/Louisville Gas and Electric Company	39,615.59	
Fuel		96,745,428.76
Coal 1,533,901.11 Tons @ $58.04 MMBtu 34,978,701.67 @ 254.54¢	89,033,194.43	
Fuel Oil 3,002,092 Gallons @ 254.67¢	7,645,323.18	
Gas Pipeline 10,618.81 Mcf @ $6.30	66,911.15	
Plant Materials and Operating Supplies		34,036,932.19
Regular Materials and Supplies	33,328,337.37	
Limestone 75,449.81 Tons @ $9.39	708,594.79	
Other Reagents	0.03	
Stores Expense Undistributed	9,914,010.27	9,914,010.27

January 26, 2012

Kentucky Utilities Company
Summary Trial Balance
December 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Emission Allowances	$ 450,462.32	$ 450,462.32
Prepayments		7,285,320.31
Insurance	3,053,761.12	
Taxes	1,008,677.16	
Lease	594,013.24	
Risk Management and Workers Compensation	75,000.00	
Other	2,553,868.79	
Unamortized Debt Expense		21,600,912.97
Carroll County 2002 Series A due 02/01/32 Var%	82,344.34	
Carroll County 2002 Series B due 02/01/32 Var%	57,229.62	
Carroll County 2002 Series C due 10/01/32 Var%	1,528,403.34	
Mercer County 2002 Series A due 02/01/32 Var%	22,988.40	
Muhlenburg County 2002 Series A due 02/01/32 Var%	63,707.11	
Carroll County 2006 Series B due 10/01/34 Var%	1,090,180.74	
Carroll County 2007 Series A due 02/01/26 5.75%	469,568.25	
Trimble County 2007 Series A due 03/01/37 6.00%	404,470.54	
Carroll County 2008 Series A due 02/01/32 Var%	690,860.09	
First Mortgage Bond due 11/01/15 1.625%	1,781,050.49	
First Mortgage Bond due 11/01/20 3.250%	3,709,504.26	
First Mortgage Bond due 11/01/40 5.125%	7,207,249.15	
Revolving Credit Agreement	4,493,356.64	
Unamortized Loss on Bonds		11,775,117.37
Refinanced and Called Bonds	11,775,117.37	
Accumulated Deferred Income Taxes		86,746,693.05
Federal	73,274,966.83	
State	13,471,726.22	
Regulatory Assets		268,828,295.77
Pension and Postretirement Benefits	113,264,146.00	
ASC 740 - Deferred Taxes	75,212,354.54	
2009 Winter Storm	49,128,217.76	
Asset Retirement Obligations	7,421,292.04	
FERC Jurisdictional Pension Expense	5,875,853.00	
Virginia Mountain Snowstorm	5,840,281.12	
VA Fuel Component Non-Current	3,794,000.00	
MISO Exit Fee	3,643,949.63	
2008 Wind Storm	1,884,484.86	
Rate Case Expenses	1,140,004.34	
EKPC FERC Transmission Cost	725,176.98	
KCCS Funding	595,432.83	
CMRG Funding	162,196.61	
General Management Audit	140,906.06	
Other Deferred Debits	45,192,019.67	45,192,019.67
Total Assets	$ 5,180,331,160.53	$ 5,180,331,160.53

January 26, 2012

Kentucky Utilities Company
Summary Trial Balance
December 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 2,128,238,257.17
Common Stock	308,139,977.56	
Less: Common Stock Expense	321,288.87	
Paid-In Capital	315,858,083.00	
Other Comprehensive Income	(2,457,900.37)	
Retained Earnings	1,490,663,791.10	
Unappropriated Undistributed Subsidiary Earnings	16,355,594.75	
Bonds		1,840,591,561.25
First Mortgage Bonds	1,489,812,156.25	
Pollution Control Bonds - Net of Reacquired Bonds	350,779,405.00	
Accounts Payable		119,658,898.66
Regular	112,165,621.49	
Employee Withholdings Payable	4,758,904.24	
Salaries and Wages Accrued	2,734,372.93	
Accounts Payable to Associated Companies		33,178,775.21
LG&E and KU Services/Louisville Gas and Electric Company	33,178,775.21	
Customers' Deposits	22,862,411.92	22,862,411.92
Taxes Accrued	10,729,937.99	10,729,937.99
Interest Accrued		10,619,839.16
Mercer County 2000 Series A due 05/01/23 Var%	1,297.07	
Carroll County 2002 Series A due 02/01/32 Var%	4,099.99	
Carroll County 2002 Series B due 02/01/32 Var%	1,193.43	
Carroll County 2002 Series C due 10/01/32 Var%	3,840.00	
Mercer County 2002 Series A due 02/01/32 Var%	3,679.72	
Muhlenburg County 2002 Series A due 02/01/32 Var%	1,193.43	
Carroll County 2004 Series A due 10/01/34 Var%	5,616.44	
Carroll County 2006 Series B due 10/01/34 Var%	5,991.78	
Carroll County 2007 Series A due 02/01/26 5.75%	85,651.04	
Trimble County 2007 Series A due 03/01/37 6.00%	44,635.00	
Carroll County 2008 Series A due 02/01/32 Var%	8,627.60	
First Mortgage Bond due 11/01/15 1.625%	677,083.33	
First Mortgage Bond due 11/01/20 3.250%	2,708,333.33	
First Mortgage Bond due 11/01/40 5.125%	6,406,250.00	
Customers' Deposits	644,960.52	
Other	17,386.48	

January 26, 2012

Kentucky Utilities Company
Summary Trial Balance
December 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Miscellaneous Current and Accrued Liabilities		$ 19,177,240.61
Vacation Pay Accrued	6,042,349.44	
Franchise Fee Payable	5,031,538.63	
Tax Collections Payable	3,805,277.87	
Customer Overpayments	3,522,167.71	
Home Energy Assistance	368,438.25	
Retirement Income Liability	351,262.96	
Other	56,205.75	
Accumulated Deferred Income Taxes		559,462,412.30
Federal	487,163,039.55	
State	72,299,372.75	
Investment Tax Credit		101,407,768.32
Advanced Coal Credit	98,634,697.00	
Job Development Credit	2,773,071.32	
Regulatory Liabilities		108,313,656.21
Deferred Taxes		
Federal	63,019,714.07	
State	19,772,068.00	
Postretirement Benefits	8,866,251.00	
Environmental Cost Recovery	6,712,019.15	
Asset Retirement Obligations	3,533,597.56	
DSM Cost Recovery	2,318,124.30	
Spare Parts	2,084,702.97	
MISO Schedule 10 Charges	1,023,179.16	
Fuel Adjustment Clause	984,000.00	
Customers' Advances for Construction		3,155,939.30
Line Extensions	2,988,276.60	
Other	167,662.70	
Asset Retirement Obligations	61,789,582.18	61,789,582.18
Other Deferred Credits	6,945,601.15	6,945,601.15
Miscellaneous Long-Term Liabilities		2,695,347.71
Workers' Compensation	2,695,347.71	
Accumulated Provision for Benefits		151,503,931.39
Pension Payable	83,440,581.39	
Postretirement Benefits - ASC 715	68,317,170.00	
Post Employment Benefits Payable	6,658,395.00	
Post Employment Medicare Subsidy	(364,214.00)	
Medicare Subsidy - ASC 715	(6,548,001.00)	
Total Liabilities and Stockholders Equity	$ 5,180,331,160.53	$ 5,180,331,160.53

Kentucky Utilities Company
Statement of Cash Flows
December 31, 2011

	Year to Date	
	2011	2010
Cash Flows from Operating Activities		
Net income	$ 176,735,396.28	$ 175,494,417.67
Items not requiring (providing) cash currently:		
Depreciation	181,926,788.12	139,282,040.69
Amortization	7,263,444.41	6,603,463.92
Deferred income taxes - net	110,690,700.68	28,662,844.90
Investment tax credit - net	(2,757,499.00)	-
Gain on disposal of assets	(74,124.22)	10,503.81
Other	3,775,271.56	(26,787,061.29)
Change in receivables	32,924,758.94	(12,131,505.75)
Change in inventory	(3,737,910.95)	(618,957.62)
Change in allowance inventory	116,116.68	408,496.90
Change in payables and accrued expenses	(23,593,058.59)	5,802,572.51
Change in regulatory assets	(53,358,837.23)	45,268,393.61
Change in regulatory liabilities	53,342,425.32	10,868,187.00
Change in other deferred debits	1,218,799.72	(2,358,473.51)
Change in other deferred credits	(1,344,903.14)	(1,458,452.00)
Pension and postretirement funding	(50,044,299.00)	(20,373,490.00)
Other	3,488,951.96	38,042,604.13
Allowance for other funds used during construction	(29,706.50)	1,489,748.97
Less: Undistributed earnings of subsidiary company	(1,923,199.00)	(3,761,027.00)
Net cash provided (used) by operating activities	434,619,116.04	384,444,306.95
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(257,149,891.51)	(428,563,722.05)
Less: Allowance for other funds used during construction	29,706.50	(1,489,748.97)
Proceeds received from sales of property	92,809.88	(4,381.08)
Change in non-hedging derivatives	-	17,947.19
Change in restricted cash	(45,500.00)	-
Other	(12,930,502.55)	(9,423,860.80)
Net cash provided (used) by investing activities	(270,003,377.68)	(439,463,765.71)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(2,875,370.31)	1,472,221,502.30
Payments for retirement of long-term debt	-	(1,298,000,000.00)
Net change in short-term debt	(10,434,000.00)	(67,540,954.00)
Dividends on common stock	(123,500,000.00)	(50,000,000.00)
Net cash provided (used) by financing activities	(136,809,370.31)	56,680,548.30
Net Increase (Decrease) in Cash and Cash Equivalents	27,806,368.05	1,661,089.53
Cash and Cash Equivalents at Beginning of Period	3,333,446.86	1,672,357.33
Cash and Cash Equivalents at End of Period	$ 31,139,814.91	$ 3,333,446.86

January 26, 2012

Kentucky Utilities Company
Analysis of Interest Charges
December 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Interest on Long-Term Debt						
Loan Agreement - Pollution Control Bonds						
Mercer County 2000 Series A due 05/01/23 Var%..............	$ 1,297.07	$ 3,735.70	$ 24,276.33	$ 42,209.43	$ 24,276.33	$ 42,209.43
Carroll County 2002 Series A due 02/01/32 Var%..............	9,776.89	13,274.79	173,627.27	148,431.00	173,627.27	148,431.00
Carroll County 2002 Series B due 02/01/32 Var%..............	1,121.10	1,522.19	19,490.49	17,020.27	19,490.49	17,020.27
Carroll County 2002 Series C due 10/01/32 Var%..............	8,000.00	42,160.00	254,410.76	687,799.96	254,410.76	687,799.96
Mercer County 2002 Series A due 02/01/32 Var%..............	3,456.71	4,693.42	58,916.16	52,479.19	58,916.16	52,479.19
Muhlenburg County 2002 Series A due 02/01/32 Var%.......	1,121.10	1,522.19	19,107.98	17,020.27	19,107.98	17,020.27
Carroll County 2004 Series A due 10/01/34 Var%..............	5,616.44	13,150.68	103,260.21	150,301.37	103,260.21	150,301.37
Carroll County 2006 Series B due 10/01/34 Var%..............	5,991.78	14,439.45	112,837.80	166,467.95	112,837.80	166,467.95
Carroll County 2007 Series A due 02/01/26 5.75%.............	85,651.04	85,651.05	1,027,812.50	1,027,812.50	1,027,812.50	1,027,812.50
Trimble County 2007 Series A due 03/01/37 6.00%............	44,635.00	44,635.00	535,620.00	535,620.00	535,620.00	535,620.00
Carroll County 2008 Series A due 02/01/32 Var%..............	8,627.60	20,287.68	161,190.94	240,227.48	161,190.94	240,227.48
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/01/15 1.625%.........................	338,541.66	338,541.67	4,062,499.99	507,812.51	4,062,499.99	507,812.51
First Mortgage Bond due 11/01/20 3.250%.........................	1,354,166.66	1,354,166.67	16,249,999.99	2,031,250.01	16,249,999.99	2,031,250.01
First Mortgage Bond due 11/01/40 5.125%.........................	3,203,125.00	3,203,125.00	38,437,500.00	4,804,687.50	38,437,500.00	4,804,687.50
Fidelia/PPL..	-	-	-	64,015,302.78	-	64,015,302.78
Total..	5,071,128.05	5,140,905.49	61,240,550.42	74,444,442.22	61,240,550.42	74,444,442.22
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense..................................	255,443.25	238,663.61	3,123,233.71	584,124.41	3,123,233.71	584,124.41
Amortization of Loss on Reacquired Debt...............................	50,414.39	50,414.39	604,972.68	604,817.50	604,972.68	604,817.50
Total..	305,857.64	289,078.00	3,728,206.39	1,188,941.91	3,728,206.39	1,188,941.91
Other Interest Charges						
Customers' Deposits..	113,597.83	107,358.30	1,363,672.66	1,363,569.87	1,363,672.66	1,363,569.87
Other Tax Deficiencies..	-	4,496.00	18,358.75	87,641.07	18,358.75	87,641.07
Interest on DSM Cost Recovery...	1,175.70	1,254.61	11,695.03	18,380.69	11,695.03	18,380.69
Interest on Debt to Associated Companies..............................	-	1,160.64	6,321.35	127,043.41	6,321.35	127,043.41
AFUDC Borrowed Funds..	(575.60)	(82,702.68)	(12,955.08)	(968,596.93)	(12,955.08)	(968,596.93)
Other Interest Expense..	260,844.22	483,825.81	3,977,734.69	2,362,787.93	3,977,734.69	2,362,787.93
Total..	375,042.15	515,392.68	5,364,827.40	2,990,826.04	5,364,827.40	2,990,826.04
Total Interest..	$ 5,752,027.84	$ 5,945,376.17	$ 70,333,584.21	$ 78,624,210.17	$ 70,333,584.21	$ 78,624,210.17

January 26, 2012

Kentucky Utilities Company
Analysis of Taxes Charged and Accrued
December 31, 2011

Kind of Taxes	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year
Taxes Charged to Accounts 408.1 and 409.1...........				
Property Taxes..	$ 1,655,126.42	$ 674,212.92	$ 18,703,289.19	$ 10,464,347.03
Unemployment..	86,058.66	62,369.89	184,481.15	193,461.61
FICA..	595,202.79	970,455.17	7,182,238.26	7,270,620.29
Public Service Commission Fee..............................	168,112.85	157,659.37	1,954,633.37	1,883,702.00
Federal Income..	(18,240,147.68)	7,587,155.50	(6,941,452.11)	61,659,449.28
State Income...	(2,662,895.90)	1,556,296.77	4,455,179.15	12,756,392.51
Miscellaneous..	3,236.52	2,334.23	91,124.49	81,348.04
Total Charged to Operating Expense..........	(18,395,306.34)	11,010,483.85	25,629,493.50	94,309,320.76
Taxes Charged to Other Accounts..........................	4,139,535.85	(5,897,255.37)	7,791,008.91	2,739,104.87
Taxes Accrued on Intercompany Accounts............	(25,041.86)	(429,585.11)	(2,315,212.66)	(3,253,773.95)
Total Taxes Charged..................................	$ (14,280,812.35)	$ 4,683,643.37	$ 31,105,289.75	$ 93,794,651.68

Analysis of Taxes Accrued - Account 236

Kind of Taxes	Taxes Accrued At Beginning Of Year	Accruals To Date This Year	Payments To Date This Year	Taxes Accrued At End Of Month
Property Taxes..	$ 8,399,528.00	$ 18,705,293.19	$ 17,611,619.47	$ 9,493,201.72
Unemployment..	75,728.12	130,701.89	135,463.57	70,966.44
FICA..	639,011.24	6,015,387.25	6,100,232.29	554,166.20
Federal Income..	12,876,014.95	(4,628,293.95)	8,247,721.00	-
State Income...	2,021,178.48	6,170,840.52	8,192,019.00	-
Kentucky Sales and Use Tax..................................	581,659.33	4,583,040.93	4,577,463.84	587,236.42
Miscellaneous..	21,662.86	128,319.92	125,615.57	24,367.21
Totals...	$ 24,614,782.98	$ 31,105,289.75	$ 44,990,134.74	$ 10,729,937.99

January 26, 2012

Kentucky Utilities Company
Summary of Utility Plant
December 31, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant in Service**						
Electric						
Electric Distribution.................................	$ 1,312,664,325.73	$ 84,170,823.72	$ (15,563,024.68)	$ 1,222,081.80	$ 69,829,880.84	$ 1,382,494,206.57
Electric General Plant..............................	125,243,994.19	14,620,240.33	(9,322,034.00)	(787,154.19)	4,511,052.14	129,755,046.33
Electric Hydro Production.......................	16,848,655.18	300,776.20	(15,190.72)	-	285,585.48	17,134,240.66
Electric Intangible Plant...........................	49,640,906.77	8,491,507.87	(3,271,886.08)	-	5,219,621.79	54,860,528.56
Electric Other Production........................	519,412,128.33	8,564,096.91	(2,076,777.74)	-	6,487,319.17	525,899,447.50
Electric Steam Production.......................	1,814,421,935.78	731,034,952.07	(11,267,159.68)	124,906,781.69	844,674,574.08	2,659,096,509.86
Electric Transmission...............................	552,965,733.49	24,104,567.75	(2,739,572.44)	517,779.11	21,882,774.42	574,848,507.91
Total 101 Accounts..................................	4,391,197,679.47	871,286,964.85	(44,255,645.34)	125,859,488.41	952,890,807.92	5,344,088,487.39
102 **Electric Plant Purchased or Sold**						
Electric						
Electric Steam...	483,341.17	-	-	-	-	483,341.17
Total 102001	483,341.17	-	-	-	-	483,341.17
105 **Plant Held for Future Use**						
Electric						
Electric Distribution.................................	792,599.21	-	-	-	-	792,599.21
Electric Steam...	120,828,152.53	-	-	(120,828,152.53)	(120,828,152.53)	-
Total 105001..	121,620,751.74	-	-	(120,828,152.53)	(120,828,152.53)	792,599.21
106 **Completed Construction Not Classified**						
Electric						
Electric Distribution.................................	36,610,963.62	(12,630,869.36)	-	-	(12,630,869.36)	23,980,094.26
Electric General Plant..............................	769,342.30	6,969,292.04	-	-	6,969,292.04	7,738,634.34
Electric Hydro Production.......................	-	11,505,517.08	-	-	11,505,517.08	11,505,517.08
Electric Intangible Plant...........................	2,685,464.69	1,103,301.47	-	-	1,103,301.47	3,788,766.16
Electric Other Production........................	3,737,695.33	(2,644,057.53)	-	-	(2,644,057.53)	1,093,637.80
Electric Steam Production.......................	910,748,505.16	57,231,936.35	-	-	57,231,936.35	967,980,441.51
Electric Transmission...............................	74,497,274.43	7,539,447.47	-	-	7,539,447.47	82,036,721.90
Total 106 Accounts..................................	1,029,049,245.53	69,074,567.52	-	-	69,074,567.52	1,098,123,813.05
121 **Nonutility Property**						
Common						
Non Utility Property................................	179,120.94	-	-	-	-	179,120.94
Total 121001	179,120.94	-	-	-	-	179,120.94
107 **Construction Work In Progress**						
Electric						
Electric..	954,430,277.48	(614,718,845.84)	-	-	(614,718,845.84)	339,711,431.64
Total 107001..	954,430,277.48	(614,718,845.84)	-	-	(614,718,845.84)	339,711,431.64
Total Plant (Non-CWIP)................................	5,542,530,138.85	940,361,532.37	(44,255,645.34)	5,031,335.88	901,137,222.91	6,443,667,361.76
Total Plant + CWIP..	6,496,960,416.33	325,642,686.53	(44,255,645.34)	5,031,335.88	286,418,377.07	6,783,378,793.40
Total Plant + CWIP - Nonutility (BS)............	$ 6,496,781,295.39	$ 325,642,686.53	$ (44,255,645.34)	$ 5,031,335.88	$ 286,418,377.07	$ 6,783,199,672.46

January 26, 2012

Kentucky Utilities Company
Summary of Utility Plant - Reserve for Depreciation of Utility Plant
December 31, 2011

	Beginning Balance	Accruals	Retirements	Transfers/ Adjustments	ARO Settlements	RWIP Transfers Out	Cost of Removal	Salvage	Other Credits	Ending Balance
Life Reserve										
Electric Distribution.....................................	$ (398,692,068.83)	$ (27,749,092.08)	$ 15,563,024.68	$ (178,184.82)	$ -	$ -	$ -	$ -	$ -	$ (411,056,321.05)
Electric Distribution - ARO..........................	(790.87)	(5,974.67)	-	-	-	-	-	-	-	(6,765.54)
Electric General Plant..................................	(57,721,732.75)	(6,272,421.07)	9,322,034.00	181,344.61	-	-	-	-	-	(54,490,775.21)
Electric Hydro Production............................	(7,765,077.65)	(123,056.83)	15,190.72	-	-	-	-	-	-	(7,872,943.76)
Electric Hydro Production - ARO................	(121.57)	(972.96)	-	-	-	-	-	-	-	(1,094.53)
Electric Other Production.............................	(160,412,820.60)	(16,722,428.28)	2,076,777.74	-	-	-	-	-	-	(175,058,471.14)
Electric Other Production - ARO.................	(84.76)	(678.84)	-	-	-	-	-	-	-	(763.60)
Electric Steam Production............................	(1,067,997,942.05)	(89,132,686.09)	11,210,464.76	(282,823.63)	-	-	-	-	-	(1,146,202,987.01)
Electric Steam Production - ARO................	(485,952.30)	(3,018,381.74)	56,694.92	(64,980.38)	-	-	-	-	-	(3,512,619.50)
Electric Transmission...................................	(211,361,531.11)	(9,343,658.72)	2,739,572.44	(9,166.52)	-	-	-	-	-	(217,974,783.91)
Electric Transmission - ARO.......................	(156.99)	(2,514.86)	-	-	-	-	-	-	-	(2,671.85)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(1,904,438,279.48)	(152,371,866.14)	40,983,759.26	(353,810.74)	-	-	-	-	-	(2,016,180,197.10)
Cost of Removal										
Electric Distribution.....................................	(195,818,054.42)	(8,132,006.70)	-	48,343.13	-	-	4,242,857.60	-	-	(199,658,860.39)
Electric General Plant..................................	207,510.70	(46,195.31)	-	(0.02)	-	-	89,267.31	-	-	250,582.68
Electric Hydro Production............................	(374,056.75)	(5,204.35)	-	-	-	-	29,260.00	-	-	(350,001.10)
Electric Other Production.............................	(3,174,464.89)	(896,010.56)	-	-	-	-	498,253.84	-	-	(3,572,221.61)
Electric Steam Production............................	(113,988,699.33)	(25,261,291.59)	-	245,753.92	-	-	2,708,676.06	-	-	(136,295,560.94)
Electric Transmission...................................	(137,175,896.62)	(2,822,661.49)	-	(1,063,020.02)	-	-	2,956,843.86	-	-	(138,104,734.27)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(450,323,661.31)	(37,163,370.00)	-	(768,922.99)	-	-	10,525,158.67	-	-	(477,730,795.63)
Salvage										
Electric Distribution.....................................	48,221,606.07	1,984,322.14	-	-	-	-	-	(646,533.89)	-	49,559,394.32
Electric General Plant..................................	149,758.57	-	-	-	-	-	-	(12,678.93)	-	137,079.64
Electric Hydro Production............................	46,518.69	-	-	-	-	-	-	-	-	46,518.69
Electric Other Production.............................	618,891.61	-	-	-	-	-	-	-	-	618,891.61
Electric Steam Production............................	20,938,580.66	4,679,717.30	-	-	-	-	-	(1,382,786.55)	-	24,235,511.41
Electric Transmission...................................	23,009,336.80	654,847.51	-	5,692.50	-	-	-	(31,874.47)	-	23,638,002.34
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	92,984,692.40	7,318,886.95	-	5,692.50	-	-	-	(2,073,873.84)	-	98,235,398.01
Total Reserves										
Electric Distribution.....................................	(546,288,517.18)	(33,896,776.64)	15,563,024.68	(129,841.69)	-	-	4,242,857.60	(646,533.89)	-	(561,155,787.12)
Electric Distribution - ARO..........................	(790.87)	(5,974.67)	-	-	-	-	-	-	-	(6,765.54)
Electric General Plant..................................	(57,364,463.48)	(6,318,616.38)	9,322,034.00	181,344.59	-	-	89,267.31	(12,678.93)	-	(54,103,112.89)
Electric Hydro Production............................	(8,092,615.71)	(128,261.18)	15,190.72	-	-	-	29,260.00	-	-	(8,176,426.17)
Electric Hydro Production - ARO................	(121.57)	(972.96)	-	-	-	-	-	-	-	(1,094.53)
Electric Other Production.............................	(162,968,393.88)	(17,618,438.84)	2,076,777.74	-	-	-	498,253.84	-	-	(178,011,801.14)
Electric Other Production - ARO.................	(84.76)	(678.84)	-	-	-	-	-	-	-	(763.60)
Electric Steam Production............................	(1,161,048,060.72)	(109,714,260.38)	11,210,464.76	(37,069.71)	-	-	2,708,676.06	(1,382,786.55)	-	(1,258,263,036.54)
Electric Steam Production - ARO................	(485,952.30)	(3,018,381.74)	56,694.92	(64,980.38)	-	-	-	-	-	(3,512,619.50)
Electric Transmission...................................	(325,528,090.93)	(11,511,472.70)	2,739,572.44	(1,066,494.04)	-	-	2,956,843.86	(31,874.47)	-	(332,441,515.84)
Electric Transmission - ARO.......................	(156.99)	(2,514.86)	-	-	-	-	-	-	-	(2,671.85)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(2,261,777,248.39)	(182,216,349.19)	40,983,759.26	(1,117,041.23)	-	-	10,525,158.67	(2,073,873.84)	-	(2,395,675,594.72)
Retirement Work in Process										
Electric..	13,605,672.01	-	-	14,675.52	(161,732.61)	(8,289,552.22)	14,696,096.93	(874,465.78)	(606,107.65)	18,384,586.20
	13,605,672.01	-	-	14,675.52	(161,732.61)	(8,289,552.22)	14,696,096.93	(874,465.78)	(606,107.65)	18,384,586.20
YTD ACTIVITY	(2,248,171,576.38)	(182,216,349.19)	40,983,759.26	(1,102,365.71)	(161,732.61)	(8,289,552.22)	25,221,255.60	(2,948,339.62)	(606,107.65)	(2,377,291,008.52)
Amortization										
Electric..	(13,755,205.98)	(7,263,444.41)	3,271,886.08	-	-	-	-	-	-	(17,746,764.31)
	(13,755,205.98)	(7,263,444.41)	3,271,886.08	-	-	-	-	-	-	(17,746,764.31)
Depreciation & Amortization Total										
Depreciation & Amortization Total...............	(2,261,926,782.36)	(189,479,793.60)	44,255,645.34	(1,102,365.71)	(161,732.61)	(8,289,552.22)	25,221,255.60	(2,948,339.62)	(606,107.65)	(2,395,037,772.83)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)...............	$ 4,234,854,513.03									$ 4,388,161,899.63

January 26, 2012

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of December 31, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues....................................	$ 129,764,309.79	$ -	$ 129,764,309.79
Rate Refunds..	-	-	-
Total Operating Revenues....................................	129,764,309.79	-	129,764,309.79
Fuel for Electric Generation.....................................	41,582,961.98	-	41,582,961.98
Power Purchased...	11,162,281.23	-	11,162,281.23
Other Operation Expenses.......................................	20,482,363.67	-	20,482,363.67
Maintenance..	8,842,126.53	-	8,842,126.53
Depreciation..	15,482,322.89	-	15,482,322.89
Amortization Expense...	649,881.53	-	649,881.53
Regulatory Credits...	(512,739.19)	-	(512,739.19)
Taxes			
Federal Income..	(18,240,147.68)	-	(18,240,147.68)
State Income..	(2,662,895.90)	-	(2,662,895.90)
Deferred Federal Income - Net..............................	26,184,610.91	50,347.82	26,234,958.73
Deferred State Income - Net..................................	3,544,807.19	9,181.97	3,553,989.16
Property and Other..	2,507,737.24	-	2,507,737.24
Loss (Gain) from Disposition of Allowances...........	-	-	-
Accretion Expense...	252,815.66	-	252,815.66
Total Operating Expenses.....................................	109,276,126.06	59,529.79	109,335,655.85
Net Operating Income...	20,488,183.73	(59,529.79)	20,428,653.94
Other Income Less Deductions			
Amortization of Investment Tax Credit.............	233,339.00	-	233,339.00
Other Income Less Deductions..........................	689,453.50	12,331.34	701,784.84
AFUDC - Equity...	1,895.10	-	1,895.10
Total Other Income Less Deductions....................	924,687.60	12,331.34	937,018.94
Income Before Interest Charges............................	21,412,871.33	(47,198.45)	21,365,672.88
Interest on Long-Term Debt....................................	5,071,128.05	(5,525.49)	5,065,602.56
Amortization of Debt Expense - Net........................	305,857.64	-	305,857.64
Other Interest Expenses...	375,617.75	-	375,617.75
AFUDC - Borrowed Funds......................................	(575.60)	-	(575.60)
Total Interest Charges...	5,752,027.84	(5,525.49)	5,746,502.35
Net Income..	$ 15,660,843.49	$ (41,672.96)	$ 15,619,170.53

January 26, 2012

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of December 31, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues....................................	$ 1,547,516,986.10	$ -	$ 1,547,516,986.10
Rate Refunds..	-	-	-
Total Operating Revenues....................................	1,547,516,986.10	-	1,547,516,986.10
Fuel for Electric Generation......................................	522,648,642.11	-	522,648,642.11
Power Purchased..	109,114,947.74	-	109,114,947.74
Other Operation Expenses..	233,508,690.94	31,612.30	233,540,303.24
Maintenance...	116,303,368.69	-	116,303,368.69
Depreciation...	181,926,788.12	-	181,926,788.12
Amortization Expense...	7,263,444.41	-	7,263,444.41
Regulatory Credits..	(5,855,639.93)	-	(5,855,639.93)
Taxes			
Federal Income...	(6,941,452.11)	-	(6,941,452.11)
State Income...	4,455,179.15	-	4,455,179.15
Deferred Federal Income - Net..............................	101,588,779.03	11,414.20	101,600,193.23
Deferred State Income - Net..................................	9,974,459.79	2,081.61	9,976,541.40
Property and Other...	28,115,766.46	-	28,115,766.46
Loss (Gain) from Disposition of Allowances...........	(3,293.39)	-	(3,293.39)
Accretion Expense..	2,827,116.86	-	2,827,116.86
Total Operating Expenses.....................................	1,304,926,797.87	45,108.11	1,304,971,905.98
Net Operating Income..	242,590,188.23	(45,108.11)	242,545,080.12
Other Income Less Deductions			
Amortization of Investment Tax Credit.............	2,686,401.00	-	2,686,401.00
Other Income Less Deductions...........................	1,749,729.68	726,082.43	2,475,812.11
AFUDC - Equity..	42,661.58	-	42,661.58
Total Other Income Less Deductions.....................	4,478,792.26	726,082.43	5,204,874.69
Income Before Interest Charges............................	247,068,980.49	680,974.32	247,749,954.81
Interest on Long-Term Debt....................................	61,240,550.42	(66,305.89)	61,174,244.53
Amortization of Debt Expense - Net.........................	3,728,206.39	-	3,728,206.39
Other Interest Expenses...	5,377,782.48	-	5,377,782.48
AFUDC - Borrowed Funds......................................	(12,955.08)	-	(12,955.08)
Total Interest Charges..	70,333,584.21	(66,305.89)	70,267,278.32
Net Income...	$ 176,735,396.28	$ 747,280.21	$ 177,482,676.49

January 26, 2012

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of December 31, 2011

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,475,266,420.61	$ 16,092,121.75	$ (1,402,398,854.76)	$ (15,200,744.29)	$ 72,867,565.85	$ 891,377.46
Add						
Net Income for Period..	15,660,843.49	-	(41,672.96)	-	15,619,170.53	-
Deductions:						
Common Dividends						
Common Stock Without Par Value..................	-	-	-	-	-	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	(263,473.00)	263,473.00	73,840.35	(73,840.35)	(189,632.65)	189,632.65
Balance at End of Period	$ 1,490,663,791.10	$ 16,355,594.75	$ (1,402,366,687.37)	$ (15,274,584.64)	$ 88,297,103.73	$ 1,081,010.11
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings................		16,355,594.75		(15,274,584.64)		1,081,010.11
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.........................		$ 6,362,326.36		$ (5,941,813.42)		$ 420,512.93

January 26, 2012

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of December 31, 2011

Retained Earnings and Undistributed Earnings	Year to Date without Purchase Accounting: Retained Earnings	Year to Date without Purchase Accounting: Undistributed Subsidiary Earnings	Year to Date Purchase Accounting: Retained Earnings	Year to Date Purchase Accounting: Undistributed Subsidiary Earnings	Year to Date Combined: Retained Earnings	Year to Date Combined: Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,439,351,593.82	$ 14,432,395.75	$ (1,404,000,051.78)	$ (14,388,500.44)	$ 35,351,542.04	$ 43,895.31
Add						
Net Income for Period ………………………………	176,735,396.28	-	747,280.21	-	177,482,676.49	-
Deductions:						
Common Dividends						
Common Stock Without Par Value....................	(123,500,000.00)	-	-	-	(123,500,000.00)	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc………………………..…………	(1,923,199.00)	1,923,199.00	886,084.20	(886,084.20)	(1,037,114.80)	1,037,114.80
Balance at End of Period …...……………………………	$ 1,490,663,791.10	$ 16,355,594.75	$ (1,402,366,687.37)	$ (15,274,584.64)	$ 88,297,103.73	$ 1,081,010.11
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings…………		16,355,594.75		(15,274,584.64)		1,081,010.11
Statutory Tax Rate…...…………………………………		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary…...………………		$ 6,362,326.36		$ (5,941,813.42)		$ 420,512.93

January 26, 2012

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of December 31, 2011

Retained Earnings and Undistributed Earnings	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,439,351,593.82	$ 14,432,395.75	$ (1,404,000,051.78)	$ (14,388,500.44)	$ 35,351,542.04	$ 43,895.31
Add						
Net Income for Period...	176,735,396.28	-	747,280.21	-	177,482,676.49	-
Deductions:						
Common Dividends						
Common Stock Without Par Value...................	(123,500,000.00)	-	-	-	(123,500,000.00)	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc..	(1,923,199.00)	1,923,199.00	886,084.20	(886,084.20)	(1,037,114.80)	1,037,114.80
Balance at End of Period	$ 1,490,663,791.10	$ 16,355,594.75	$ (1,402,366,687.37)	$ (15,274,584.64)	$ 88,297,103.73	$ 1,081,010.11

Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings.................		16,355,594.75		(15,274,584.64)		1,081,010.11
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary..........................		$ 6,362,326.36		$ (5,941,813.42)		$ 420,512.93

Combined Balance of Retained Earnings	12 MONTHS 12/31/2011	12 MONTHS 12/31/2010
Retained Earnings at Beginning of Period.......................	$ 35,395,437.35	$ 1,328,289,571.90
Net Income for Period	177,482,676.49	175,430,252.05
FIN 48 Adjustment..	-	-
Subtotal..	212,878,113.84	1,503,719,823.95
Deduct		
Purchase Accounting Adjustment...............................	-	1,418,324,386.60
Dividends on Common Stock.....................................	123,500,000.00	50,000,000.00
Retained Earnings at End of Period.................................	$ 89,378,113.84	$ 35,395,437.35

January 26, 2012

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of December 31, 2011

Assets	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 6,783,199,672.46	$ -	$ 6,783,199,672.46
Less Reserves for Depreciation and Amortization.....	2,395,037,772.83	-	2,395,037,772.83
Total..	4,388,161,899.63	-	4,388,161,899.63
Investments			
Electric Energy, Inc...	13,628,644.55	16,687,918.11	30,316,562.66
Ohio Valley Electric Corporation.............................	250,000.00	-	250,000.00
Nonutility Property - Less Reserve...........................	179,120.94	-	179,120.94
Special Funds...	-	-	-
Total..	14,057,765.49	16,687,918.11	30,745,683.60
Current and Accrued Assets			
Cash..	31,096,140.42	-	31,096,140.42
Special Deposits..	45,500.00	-	45,500.00
Temporary Cash Investments.................................	43,674.49	-	43,674.49
Accounts Receivable-Less Reserve........................	164,311,372.23	-	164,311,372.23
Accounts Receivable from Assoc Companies..........	39,615.59	-	39,615.59
Materials & Supplies-At Average Cost			
Fuel..	96,745,428.76	-	96,745,428.76
Plant Materials & Operating Supplies..................	34,036,932.19	-	34,036,932.19
Stores Expense..	9,914,010.27	-	9,914,010.27
Allowance Inventory..	450,462.32	-	450,462.32
Prepayments..	7,285,320.31	-	7,285,320.31
Miscellaneous Current & Accrued Assets..............	-	-	-
Total..	343,968,456.58	-	343,968,456.58
Deferred Debits and Other			
Unamortized Debt Expense......................................	21,600,912.97	(4,409,752.43)	17,191,160.54
Unamortized Loss on Bonds....................................	11,775,117.37	-	11,775,117.37
Accumulated Deferred Income Taxes.......................	86,746,693.05	57,520,733.36	144,267,426.41
Deferred Regulatory Assets.....................................	268,828,295.77	11,230,898.79	280,059,194.56
Other Deferred Debits..	45,192,019.67	139,962,964.68	185,154,984.35
Goodwill..	-	607,404,368.23	607,404,368.23
Total..	434,143,038.83	811,709,212.63	1,245,852,251.46
Total Assets..	$ 5,180,331,160.53	$ 828,397,130.74	$ 6,008,728,291.27

January 26, 2012

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of December 31, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Proprietary Capital			
Common Stock..	$ 308,139,977.56	$ -	$ 308,139,977.56
Less: Common Stock Expense....................................	321,288.87	-	321,288.87
Paid-In Capital..	315,858,083.00	2,032,588,750.94	2,348,446,833.94
Other Comprehensive Income.....................................	(2,457,900.37)	1,990,823.26	(467,077.11)
Retained Earnings..	1,490,663,791.10	(1,402,366,687.37)	88,297,103.73
Unappropriated Undistributed Subsidiary Earnings....	16,355,594.75	(15,274,584.64)	1,081,010.11
Total Proprietary Capital..	2,128,238,257.17	616,938,302.19	2,745,176,559.36
Pollution Control Bonds - Net of Reacquired Bonds...	350,779,405.00	1,084,098.13	351,863,503.13
First Mortgage Bonds..	1,489,812,156.25	-	1,489,812,156.25
Total Long-Term Debt...	1,840,591,561.25	1,084,098.13	1,841,675,659.38
Total Capitalization..	3,968,829,818.42	618,022,400.32	4,586,852,218.74
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Accounts Payable...	119,658,898.66	-	119,658,898.66
Accounts Payable to Associated Companies................	33,178,775.21	-	33,178,775.21
Customer Deposits...	22,862,411.92	-	22,862,411.92
Taxes Accrued..	10,729,937.99	-	10,729,937.99
Interest Accrued...	10,619,839.16	-	10,619,839.16
Dividends Declared..	-	-	-
Miscellaneous Current and Accrued Liabilities...........	19,177,240.61	-	19,177,240.61
Total..	216,227,103.55	-	216,227,103.55
Deferred Credits and Other			
Accumulated Deferred Income Taxes..........................	559,462,412.30	63,590,619.38	623,053,031.68
Investment Tax Credit..	101,407,768.32	-	101,407,768.32
Regulatory Liabilities...	108,313,656.21	139,962,964.68	248,276,620.89
Customer Advances for Construction..........................	3,155,939.30	-	3,155,939.30
Asset Retirement Obligations......................................	61,789,582.18	-	61,789,582.18
Other Deferred Credits...	6,945,601.15	6,821,146.36	13,766,747.51
Miscellaneous Long-Term Liabilities..........................	2,695,347.71	-	2,695,347.71
Accum Provision for Postretirement Benefits.............	151,503,931.39	-	151,503,931.39
Total..	995,274,238.56	210,374,730.42	1,205,648,968.98
Total Liabilities and Stockholders' Equity.........................	$ 5,180,331,160.53	$ 828,397,130.74	$ 6,008,728,291.27

January 26, 2012

KENTUCKY UTILITIES COMPANY

Financial Reports

November 30, 2011

Index
Financial and Operating Reports

Kentucky Utilities Company
November 30, 2011

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2011 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows, unless otherwise noted.

Kentucky Utilities Company
Comparative Statement of Income
November 30, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 117,741,030.82	$ 104,843,595.62	$ 12,897,435.20	12.30
Rate Refunds	-	-	-	-
Total Operating Revenues	117,741,030.82	104,843,595.62	12,897,435.20	12.30
Fuel for Electric Generation	38,916,400.82	29,899,702.27	9,016,698.55	30.16
Power Purchased	6,841,266.72	11,711,535.17	(4,870,268.45)	(41.59)
Other Operation Expenses	18,620,233.99	15,950,496.86	2,669,737.13	16.74
Maintenance	8,771,745.72	10,053,520.73	(1,281,775.01)	(12.75)
Depreciation	15,367,965.42	12,315,382.87	3,052,582.55	24.79
Amortization Expense	657,712.91	555,219.51	102,493.40	18.46
Regulatory Credits	(507,360.58)	(467,649.75)	(39,710.83)	(8.49)
Taxes				
Federal Income	6,848,150.40	5,745,607.58	1,102,542.82	19.19
State Income	1,248,905.55	1,047,831.17	201,074.38	19.19
Deferred Federal Income - Net	83,583.78	-	83,583.78	100.00
Deferred State Income - Net	(11,910.45)	-	(11,910.45)	(100.00)
Property and Other	2,245,169.11	1,000,668.38	1,244,500.73	124.37
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	-	-	-	-
Accretion Expense	251,742.18	222,740.95	29,001.23	13.02
Total Operating Expenses	99,333,605.57	88,035,055.74	11,298,549.83	12.83
Net Operating Income	18,407,425.25	16,808,539.88	1,598,885.37	9.51
Other Income Less Deductions				
Amortization of Investment Tax Credit	233,343.00	5,925.00	227,418.00	3,838.28
Other Income Less Deductions	(83,564.67)	(469,311.87)	385,747.20	82.19
AFUDC - Equity	6,598.45	104,422.08	(97,823.63)	(93.68)
Total Other Income Less Deductions	156,376.78	(358,964.79)	515,341.57	143.56
Income Before Interest Charges	18,563,802.03	16,449,575.09	2,114,226.94	12.85
Interest on Long-Term Debt	5,076,988.94	5,736,399.90	(659,410.96)	(11.50)
Amortization of Debt Expense - Net	305,512.79	215,533.23	89,979.56	41.75
Other Interest Expenses	380,396.19	269,022.98	111,373.21	41.40
AFUDC - Borrowed Funds	(2,001.80)	(82,830.32)	80,828.52	97.58
Total Interest Charges	5,760,896.12	6,138,125.79	(377,229.67)	(6.15)
Net Income	$ 12,802,905.91	$ 10,311,449.30	$ 2,491,456.61	24.16

December 22, 2011

Kentucky Utilities Company
Comparative Statement of Income
November 30, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 1,417,752,676.31	$ 1,353,412,105.29	$ 64,340,571.02	4.75
Rate Refunds	-	(632,383.92)	632,383.92	100.00
Total Operating Revenues	1,417,752,676.31	1,352,779,721.37	64,972,954.94	4.80
Fuel for Electric Generation	481,065,680.13	447,190,000.27	33,875,679.86	7.58
Power Purchased	97,952,666.51	158,697,167.91	(60,744,501.40)	(38.28)
Other Operation Expenses	213,026,327.27	194,819,360.35	18,206,966.92	9.35
Maintenance	107,461,242.16	94,783,023.47	12,678,218.69	13.38
Depreciation	166,444,465.23	126,852,236.92	39,592,228.31	31.21
Amortization Expense	6,613,562.88	6,047,571.49	565,991.39	9.36
Regulatory Credits	(5,342,900.74)	(4,683,677.77)	(659,222.97)	(14.07)
Taxes				
Federal Income	11,298,695.57	54,072,293.78	(42,773,598.21)	(79.10)
State Income	7,118,075.05	11,200,095.74	(4,082,020.69)	(36.45)
Deferred Federal Income - Net	75,404,168.12	18,307,159.67	57,097,008.45	311.88
Deferred State Income - Net	6,429,652.60	2,754,931.60	3,674,721.00	133.39
Property and Other	25,608,029.22	18,026,447.39	7,581,581.83	42.06
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	(3,293.39)	(44,023.81)	40,730.42	92.52
Accretion Expense	2,574,301.20	3,275,223.05	(700,921.85)	(21.40)
Total Operating Expenses	1,195,650,671.81	1,131,297,810.06	64,352,861.75	5.69
Net Operating Income	222,102,004.50	221,481,911.31	620,093.19	0.28
Other Income Less Deductions				
Amortization of Investment Tax Credit	2,453,062.00	65,175.00	2,387,887.00	3,663.81
Other Income Less Deductions	1,060,276.18	1,061,120.82	(844.64)	(0.08)
AFUDC - Equity	40,766.48	416,890.87	(376,124.39)	(90.22)
Total Other Income Less Deductions	3,554,104.66	1,543,186.69	2,010,917.97	130.31
Income Before Interest Charges	225,656,109.16	223,025,098.00	2,631,011.16	1.18
Interest on Long-Term Debt	56,169,422.37	69,303,536.73	(13,134,114.36)	(18.95)
Amortization of Debt Expense - Net	3,422,348.75	899,863.91	2,522,484.84	280.32
Other Interest Expenses	5,002,164.73	3,361,327.61	1,640,837.12	48.82
AFUDC - Borrowed Funds	(12,379.48)	(885,894.25)	873,514.77	98.60
Total Interest Charges	64,581,556.37	72,678,834.00	(8,097,277.63)	(11.14)
Net Income	$ 161,074,552.79	$ 150,346,264.00	$ 10,728,288.79	7.14

December 22, 2011

Kentucky Utilities Company
Comparative Statement of Income
November 30, 2011

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues.....................................	$ 1,576,682,666.94	$ 1,484,402,650.65	$ 92,280,016.29	6.22
Rate Refunds..	-	(943,383.92)	943,383.92	100.00
Total Operating Revenues......................................	1,576,682,666.94	1,483,459,266.73	93,223,400.21	6.28
Fuel for Electric Generation......................................	529,959,867.99	490,830,409.93	39,129,458.06	7.97
Power Purchased...	113,877,435.87	174,700,338.55	(60,822,902.68)	(34.82)
Other Operation Expenses..	234,854,194.69	213,909,704.59	20,944,490.10	9.79
Maintenance..	120,492,203.49	110,670,627.14	9,821,576.35	8.87
Depreciation..	178,874,269.00	137,601,349.29	41,272,919.71	29.99
Amortization Expense...	7,169,455.31	6,602,520.19	566,935.12	8.59
Regulatory Credits..	(5,808,780.32)	(4,887,951.71)	(920,828.61)	(18.84)
Taxes				
Federal Income...	18,885,851.07	59,469,701.01	(40,583,849.94)	(68.24)
State Income...	8,674,371.82	11,349,851.85	(2,675,480.03)	(23.57)
Deferred Federal Income - Net...............................	79,372,460.20	14,912,204.40	64,460,255.80	432.27
Deferred State Income - Net...................................	6,985,759.18	3,406,052.96	3,579,706.22	105.10
Property and Other...	27,475,060.80	19,390,053.91	8,085,006.89	41.70
Investment Tax Credit..	-	2,958,591.69	(2,958,591.69)	(100.00)
Loss (Gain) from Disposition of Allowances...........	(16,020.32)	(44,023.81)	28,003.49	63.61
Accretion Expense..	2,797,983.09	3,454,751.91	(656,768.82)	(19.01)
Total Operating Expenses......................................	1,323,594,111.87	1,244,324,181.90	79,269,929.97	6.37
Net Operating Income...	253,088,555.07	239,135,084.83	13,953,470.24	5.84
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	2,458,987.00	87,712.50	2,371,274.50	2,703.46
Other Income Less Deductions...........................	1,057,069.28	1,302,155.77	(245,086.49)	(18.82)
AFUDC - Equity...	145,027.65	638,202.58	(493,174.93)	(77.28)
Total Other Income Less Deductions......................	3,661,083.93	2,028,070.85	1,633,013.08	80.52
Income Before Interest Charges.............................	256,749,639.00	241,163,155.68	15,586,483.32	6.46
Interest on Long-Term Debt......................................	61,310,327.86	75,638,411.79	(14,328,083.93)	(18.94)
Amortization of Debt Expense - Net.........................	3,711,426.75	968,259.11	2,743,167.64	283.31
Other Interest Expenses..	5,600,260.09	3,637,980.22	1,962,279.87	53.94
AFUDC - Borrowed Funds.......................................	(95,082.16)	(980,162.23)	885,080.07	90.30
Total Interest Charges..	70,526,932.54	79,264,488.89	(8,737,556.35)	(11.02)
Net Income..	$ 186,222,706.46	$ 161,898,666.79	$ 24,324,039.67	15.02

December 22, 2011

Kentucky Utilities Company
Analysis of Retained Earnings
November 30, 2011

Retained Earnings and Undistributed Earnings	Current Month: Total Retained Earnings	Current Month: Undistributed Subsidiary Earnings	Year to Date: Total Retained Earnings	Year to Date: Undistributed Subsidiary Earnings	Year Ended Current Month: Total Retained Earnings	Year Ended Current Month: Undistributed Subsidiary Earnings
Balance at Beginning of Period..	$ 1,498,556,521.70	$ 15,999,114.75	$ 1,439,351,593.82	$ 14,432,395.75	$ 1,414,639,467.15	$ 13,996,368.75
Add:						
Net Income for Period..	12,802,905.91	-	161,074,552.79	-	186,222,706.46	-
Deduct:						
Common Dividends						
Common Stock Without Par Value	(36,000,000.00)	-	(123,500,000.00)	-	(123,500,000.00)	-
EE Inc..	(93,007.00)	93,007.00	(1,659,726.00)	1,659,726.00	(2,095,753.00)	2,095,753.00
Balance at End of Period..	$ 1,475,266,420.61	$ 16,092,121.75	$ 1,475,266,420.61	$ 16,092,121.75	$ 1,475,266,420.61	$ 16,092,121.75
Deferred Taxes Related to Undistributed Subsidiary Earnings		-		-		-
Balance of Undistributed Subsidiary Earnings.............................		16,092,121.75		16,092,121.75		16,092,121.75
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.......................................		$ 6,259,835.36		$ 6,259,835.36		$ 6,259,835.36

December 22, 2011

Kentucky Utilities Company
Comparative Balance Sheets as of November 30, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,717,661,067.20	$ 6,466,499,138.13
Less: Reserves for Depreciation and Amortization	2,385,643,296.46	2,254,923,633.77
Total	4,332,017,770.74	4,211,575,504.36
Investments		
Electric Energy, Inc	13,357,842.55	12,031,529.55
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	179,154.72	179,120.94
Total	13,786,997.27	12,460,650.49
Current and Accrued Assets		
Cash	33,369,232.56	10,028,855.56
Special Deposits	-	-
Temporary Cash Investments	61,337,721.56	455.80
Accounts Receivable-Less Reserve	143,602,834.36	160,275,137.40
Accounts Receivable from Associated Companies	2,281.36	12,671.24
Materials and Supplies-At Average Cost		
Fuel	98,217,300.29	105,878,435.32
Plant Materials and Operating Supplies	34,369,554.14	32,801,253.61
Stores Expense	10,186,164.04	8,642,709.54
Emission Allowances	460,964.54	587,876.60
Prepayments	6,481,180.70	14,729,547.86
Miscellaneous Current and Accrued Assets	0.01	89,101.94
Total	388,027,233.56	333,046,044.87
Deferred Debits and Other		
Unamortized Debt Expense	21,783,072.56	20,357,339.69
Unamortized Loss on Bonds	11,825,531.76	12,430,504.44
Accumulated Deferred Income Taxes	88,863,654.64	54,567,840.52
Deferred Regulatory Assets	274,713,424.52	214,554,260.63
Other Deferred Debits	45,221,104.51	41,828,149.70
Total	442,406,787.99	343,738,094.98
Total Assets	$ 5,176,238,789.56	$ 4,900,820,294.70

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	315,858,083.00	315,858,083.00
Other Comprehensive Income	(2,456,676.43)	(1,992,250.55)
Retained Earnings	1,475,266,420.61	1,414,639,467.15
Unappropriated Undistributed Subsidiary Earnings	16,092,121.75	13,996,368.75
Total Proprietary Capital	2,112,578,637.62	2,050,320,357.04
Pollution Control Bonds	350,779,405.00	350,779,405.00
First Mortgage Bonds	1,489,759,218.75	1,489,123,968.75
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,840,538,623.75	1,839,903,373.75
Total Capitalization	3,953,117,261.37	3,890,223,730.79
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Accounts Payable	96,368,319.57	97,245,111.09
Accounts Payable to Associated Companies	29,090,154.96	34,973,743.47
Customer Deposits	23,058,149.37	22,289,680.62
Taxes Accrued	37,368,137.96	9,216,475.34
Interest Accrued	6,272,253.56	3,021,342.90
Dividends Declared	36,000,000.00	-
Miscellaneous Current and Accrued Liabilities	16,957,328.53	15,841,690.46
Total	245,114,343.95	182,588,043.88
Deferred Credits and Other		
Accumulated Deferred Income Taxes	531,911,216.48	411,111,093.87
Investment Tax Credit	101,641,107.32	104,100,094.32
Regulatory Liabilities	112,488,037.07	45,911,478.12
Customer Advances for Construction	3,166,933.71	2,879,811.31
Asset Retirement Obligations	60,183,309.93	53,757,624.52
Other Deferred Credits	32,647,513.35	37,383,268.54
Miscellaneous Long-Term Liabilities	2,747,598.99	2,572,412.83
Accum Provision for Postretirement Benefits	133,221,467.39	170,292,736.52
Total	978,007,184.24	828,008,520.03
Total Liabilities and Stockholders Equity	$ 5,176,238,789.56	$ 4,900,820,294.70

December 22, 2011

Kentucky Utilities Company
Statement of Capitalization and Short-Term Debt
November 30, 2011

	Authorized Shares	Issued and Outstanding Shares	Issued and Outstanding Amount	Percent of Total Capital
Proprietary Capital				
Common Stock - Without Par...	80,000,000	37,817,878	$ 308,139,977.56	
Less: Common Stock Expense..			321,288.87	
Paid-In Capital..			315,858,083.00	
Other Comprehensive Income...			(2,456,676.43)	
Retained Earnings...			1,475,266,420.61	
Unappropriated Undistributed Subsidiary Earnings.............			16,092,121.75	
Total Proprietary Capital..			2,112,578,637.62	53.44
Long-Term Debt				
Pollution Control Bonds				
Mercer County 2000 Series A due 05/01/23 Var%...........			12,900,000.00	
Carroll County 2002 Series A due 02/01/32 Var%...........			20,930,000.00	
Carroll County 2002 Series B due 02/01/32 Var%...........			2,400,000.00	
Carroll County 2002 Series C due 10/01/32 Var%...........			96,000,000.00	
Mercer County 2002 Series A due 02/01/32 Var%...........			7,400,000.00	
Muhlenburg County 2002 Series A due 02/01/32 Var%...			2,400,000.00	
Carroll County 2004 Series A due 10/01/34 Var%...........			50,000,000.00	
Carroll County 2006 Series B due 10/01/34 Var%...........			54,000,000.00	
Carroll County 2007 Series A due 02/01/26 5.75%..........			17,875,000.00	
Trimble County 2007 Series A due 03/01/37 6.00%.........			8,927,000.00	
Carroll County 2008 Series A due 02/01/32 Var%...........			77,947,405.00	
Total Pollution Control Bonds..			350,779,405.00	8.87
First Mortgage Bonds				
First Mortgage Bond due 11/01/15 1.625%........................			250,000,000.00	
First Mortgage Bond due 11/01/20 3.250%.......................			500,000,000.00	
First Mortgage Bond due 11/01/40 5.125%.......................			750,000,000.00	
Total First Mortgage Bonds..			1,500,000,000.00	37.94
Less: First Mortgage Bonds Debt Discount				
First Mortgage Bond due 11/01/15 1.625%........................			(692,708.35)	
First Mortgage Bond due 11/01/20 3.250%.......................			(1,693,125.00)	
First Mortgage Bond due 11/01/40 5.125%.......................			(7,854,947.90)	
			(10,240,781.25)	(0.25)
Total First Mortgage Bonds - Net of Debt Discount............			1,489,759,218.75	37.69
Total Capitalization..			$ 3,953,117,261.37	100.00

December 22, 2011

Kentucky Utilities Company
Summary Trial Balance
November 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 6,717,661,067.20	$ 6,717,661,067.20
Reserves for Depreciation and Amortization		(2,385,643,296.46)
Depreciation of Plant	(2,366,655,612.10)	
Amortization of Plant	(18,987,684.36)	
Investments		13,786,997.27
Electric Energy, Inc	13,357,842.55	
Ohio Valley Electric Corporation	250,000.00	
Nonutility Property Reserve	179,154.72	
Cash	33,369,232.56	33,369,232.56
Temporary Cash Investments	61,337,721.56	61,337,721.56
Accounts Receivable - Less Reserve		143,602,834.36
Unbilled Revenues	72,261,143.92	
Customers - Active	63,144,673.32	
IMPA	2,136,044.39	
IMEA	2,008,851.91	
Transmission Sales	1,016,863.48	
Damage Claims	260,281.71	
Bechtel Liquidated Damages	24,300.00	
Sundry Accounts Receivable	5,078.16	
Other	5,039,648.44	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	7,717,985.10	
Accrual	(5,608,415.86)	
Recoveries	(2,109,435.05)	
Reserve	(2,009,276.00)	
A/R Miscellaneous	(284,909.16)	
Accounts Receivable from Associated Companies		2,281.36
LG&E - KU Energy Services/Louisville Gas and Electric Company	2,281.36	
Fuel		98,217,300.29
Coal 1,587,593.21 Tons @ $57.29 MMBtu 36,313,407.57 @ 250.47¢	90,954,005.80	
Fuel Oil 2,866,883 Gallons @ 251.45¢	7,208,852.31	
Gas Pipeline 11,712.81 Mcf @ $4.65	54,442.18	
Plant Materials and Operating Supplies		34,369,554.14
Regular Materials and Supplies	33,708,413.04	
Limestone 70,295.20 Tons @ $9.41	661,141.07	
Other Reagents	0.03	
Stores Expense Undistributed	10,186,164.04	10,186,164.04

December 22, 2011

Kentucky Utilities Company
Summary Trial Balance
November 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Emission Allowances	$ 460,964.54	$ 460,964.54
Prepayments		6,481,180.70
Insurance	1,893,020.97	
Taxes	1,176,790.01	
Lease	606,926.58	
Risk Management and Workers Compensation	75,000.00	
Other	2,729,443.14	
Miscellaneous Current Assets		0.01
Derivative Asset - Non-Hedging	0.01	
Unamortized Debt Expense		21,783,072.56
Carroll County 2002 Series A due 02/01/32 Var%	82,686.34	
Carroll County 2002 Series B due 02/01/32 Var%	57,467.62	
Carroll County 2002 Series C due 10/01/32 Var%	1,534,541.51	
Mercer County 2002 Series A due 02/01/32 Var%	23,083.40	
Muhlenburg County 2002 Series A due 02/01/32 Var%	63,972.11	
Carroll County 2006 Series B due 10/01/34 Var%	1,094,174.08	
Carroll County 2007 Series A due 02/01/26 5.75%	472,346.76	
Trimble County 2007 Series A due 03/01/37 6.00%	405,809.85	
Carroll County 2008 Series A due 02/01/32 Var%	693,726.73	
First Mortgage Bond due 11/01/15 1.625%	1,819,477.67	
First Mortgage Bond due 11/01/20 3.250%	3,744,367.59	
First Mortgage Bond due 11/01/40 5.125%	7,228,052.57	
Revolving Credit Agreement	4,563,366.33	
Unamortized Loss on Bonds		11,825,531.76
Refinanced and Called Bonds	11,825,531.76	
Accumulated Deferred Income Taxes		88,863,654.64
Federal	75,553,201.84	
State	13,310,452.80	
Regulatory Assets		274,713,424.52
Pension and Postretirement Benefits	117,274,368.11	
ASC 740 - Deferred Taxes	76,256,219.44	
2009 Winter Storm	49,605,190.74	
Asset Retirement Obligations	6,962,892.90	
Virginia Mountain Snowstorm	5,940,975.62	
FERC Jurisdictional Pension Expense	5,794,187.91	
VA Fuel Component Non-Current	4,302,000.00	
MISO Exit Fee	3,761,116.42	
2008 Wind Storm	1,902,780.83	
Rate Case Expenses	1,234,344.47	
EKPC FERC Transmission Cost	753,068.40	
KCCS Funding	614,640.34	
CMRG Funding	170,733.28	
General Management Audit	140,906.06	
Other Deferred Debits	45,221,104.51	45,221,104.51
Total Assets	$ 5,176,238,789.56	$ 5,176,238,789.56

December 22, 2011

Kentucky Utilities Company
Summary Trial Balance
November 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 2,112,578,637.62
Common Stock	308,139,977.56	
Less: Common Stock Expense	321,288.87	
Paid-In Capital	315,858,083.00	
Other Comprehensive Income	(2,456,676.43)	
Retained Earnings	1,475,266,420.61	
Unappropriated Undistributed Subsidiary Earnings	16,092,121.75	
Bonds		1,840,538,623.75
First Mortgage Bonds	1,489,759,218.75	
Pollution Control Bonds - Net of Reacquired Bonds	350,779,405.00	
Accounts Payable		96,368,319.57
Regular	94,369,784.04	
Salaries and Wages Accrued	1,962,278.47	
Employee Withholdings Payable	36,257.06	
Accounts Payable to Associated Companies		29,090,154.96
LG&E - KU Energy Services/Louisville Gas and Electric Company	29,090,154.96	
Customers' Deposits	23,058,149.37	23,058,149.37
Taxes Accrued	37,368,137.96	37,368,137.96
Interest Accrued		6,272,253.56
Mercer County 2000 Series A due 05/01/23 Var%	1,562.14	
Carroll County 2002 Series A due 02/01/32 Var%	4,415.37	
Carroll County 2002 Series B due 02/01/32 Var%	72.33	
Carroll County 2002 Series C due 10/01/32 Var%	7,040.00	
Mercer County 2002 Series A due 02/01/32 Var%	223.01	
Muhlenburg County 2002 Series A due 02/01/32 Var%	72.33	
Carroll County 2004 Series A due 10/01/34 Var%	5,657.53	
Carroll County 2006 Series B due 10/01/34 Var%	6,050.96	
Carroll County 2007 Series A due 02/01/26 5.75%	513,906.25	
Trimble County 2007 Series A due 03/01/37 6.00%	267,810.00	
Carroll County 2008 Series A due 02/01/32 Var%	8,713.02	
First Mortgage Bond due 11/01/15 1.625%	338,541.67	
First Mortgage Bond due 11/01/20 3.250%	1,354,166.67	
First Mortgage Bond due 11/01/40 5.125%	3,203,125.00	
Customers' Deposits	544,686.50	
Other	16,210.78	
Dividends Declared		36,000,000.00
Dividend Payable to LG&E and KU Energy LLC	36,000,000.00	

December 22, 2011

Kentucky Utilities Company
Summary Trial Balance
November 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Miscellaneous Current and Accrued Liabilities		$ 16,957,328.53
Vacation Pay Accrued	6,508,063.88	
Tax Collections Payable	3,416,094.35	
Franchise Fee Payable	3,547,339.20	
Customer Overpayments	3,131,743.62	
Home Energy Assistance	300,834.62	
Derivative Liabilities - Non-Hedging	0.03	
Escheated Deposits	(23.52)	
Other	53,276.35	
Accumulated Deferred Income Taxes		531,911,216.48
Federal	463,084,606.63	
State	68,826,609.85	
Investment Tax Credit		101,641,107.32
Advanced Coal Credit	98,862,111.00	
Job Development Credit	2,778,996.32	
Regulatory Liabilities		112,488,037.07
Deferred Taxes		
Federal	63,801,908.03	
State	19,969,510.71	
Postretirement Benefits	9,787,090.00	
Environmental Cost Recovery	5,475,009.15	
Asset Retirement Obligations	4,604,871.26	
DSM Cost Recovery	3,678,098.98	
Fuel Adjustment Clause	2,202,000.00	
Spare Parts	1,981,952.58	
MISO Schedule 10 Charges	987,596.36	
Customers' Advances for Construction		3,166,933.71
Line Extensions	3,008,147.09	
Other	158,786.62	
Asset Retirement Obligations	60,183,309.93	60,183,309.93
Other Deferred Credits	32,647,513.35	32,647,513.35
Miscellaneous Long-Term Liabilities		2,747,598.99
Workers' Compensation	2,747,598.99	
Accumulated Provision for Benefits		133,221,467.39
Pension Payable	70,301,999.50	
Postretirement Benefits - ASC 715	63,468,557.24	
Post Employment Benefits Payable	5,554,516.00	
Post Employment Medicare Subsidy	(382,793.62)	
Medicare Subsidy - ASC 715	(5,720,811.73)	
Total Liabilities and Stockholders Equity	$ 5,176,238,789.56	$ 5,176,238,789.56

December 22, 2011

Kentucky Utilities Company
Statement of Cash Flows
November 30, 2011

	Year to Date 2011	Year to Date 2010
Cash Flows from Operating Activities		
Net income	$ 161,074,552.79	$ 150,346,264.00
Items not requiring (providing) cash currently:		
Depreciation	166,444,465.23	126,852,236.92
Amortization	6,613,562.88	6,047,571.49
Deferred income taxes - net	81,016,618.27	22,433,628.09
Investment tax credit - net	(2,518,235.00)	-
Gain on disposal of assets	(72,906.52)	(14,519.80)
Other	4,354,774.84	13,298,983.47
Change in receivables	65,489,405.60	39,903,399.45
Change in inventory	(5,884,486.79)	(11,627,685.25)
Change in allowance inventory	105,614.46	387,199.30
Change in payables and accrued expenses	28,549,224.40	(27,347,966.79)
Change in regulatory assets	(59,224,936.57)	39,592,800.42
Change in regulatory liabilities	57,414,055.79	1,667,034.72
Change in other deferred debits	(26,571,850.94)	(1,306,695.67)
Change in other deferred credits	24,505,841.36	27,230,759.10
Pension and postretirement funding	(47,364,100.00)	(17,955,700.00)
Other	(4,158,271.33)	(48,652,209.80)
Less: Allowance for other funds used during construction	(28,387.00)	(1,302,785.12)
Less: Undistributed earnings of subsidiary company	(1,659,726.00)	(3,325,000.00)
Net cash provided (used) by operating activities	448,085,215.47	316,227,314.53
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(208,662,460.56)	(357,391,810.27)
Less: Allowance for other funds used during construction	28,387.00	1,302,785.12
Proceeds received from sale of property	91,592.18	10,503.81
Change in non-hedging derivatives	-	19,719.50
Other	(11,380,202.68)	-
Net cash provided (used) by investing activities	(219,922,684.06)	(356,058,801.84)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(2,855,024.15)	2,772,163,395.34
Payments for retirement of long-term debt	-	(2,596,000,000.00)
Net change in short-term debt	(10,434,000.00)	(77,974,954.00)
Dividends on common stock	(123,500,000.00)	(50,000,000.00)
Net cash provided (used) by financing activities	(136,789,024.15)	48,188,441.34
Net Increase (Decrease) in Cash and Cash Equivalents	91,373,507.26	8,356,954.03
Cash and Cash Equivalents at Beginning of Period	3,333,446.86	1,672,357.33
Cash and Cash Equivalents at End of Period	$ 94,706,954.12	$ 10,029,311.36

December 22, 2011

Kentucky Utilities Company
Analysis of Interest Charges
November 30, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Interest on Long-Term Debt						
Loan Agreement - Pollution Control Bonds						
Mercer County 2000 Series A due 05/01/23 Var%..............	$ 1,562.14	$ 3,792.25	$ 22,979.26	$ 38,473.73	$ 26,714.96	$ 43,280.31
Carroll County 2002 Series A due 02/01/32 Var%..............	9,461.51	12,127.92	163,850.38	135,156.21	177,125.17	152,645.66
Carroll County 2002 Series B due 02/01/32 Var%..............	1,084.93	1,390.68	18,369.39	15,498.08	19,891.58	17,503.56
Carroll County 2002 Series C due 10/01/32 Var%..............	13,909.33	42,240.00	246,410.76	645,639.96	288,570.76	665,965.29
Mercer County 2002 Series A due 02/01/32 Var%..............	3,345.20	4,287.94	55,459.45	47,785.77	60,152.87	53,969.33
Muhlenburg County 2002 Series A due 02/01/32 Var%.......	1,084.93	1,390.68	17,986.88	15,498.08	19,509.07	17,503.56
Carroll County 2004 Series A due 10/01/34 Var%..............	5,657.54	12,301.37	97,643.77	137,150.69	110,794.45	150,273.98
Carroll County 2006 Series B due 10/01/34 Var%..............	6,050.96	13,211.51	106,846.02	152,028.50	121,285.47	168,731.51
Carroll County 2007 Series A due 02/01/26 5.75%.............	85,651.04	85,651.03	942,161.46	942,161.45	1,027,812.51	1,027,812.49
Trimble County 2007 Series A due 03/01/37 6.00%............	44,635.00	44,635.00	490,985.00	490,985.00	535,620.00	535,620.00
Carroll County 2008 Series A due 02/01/32 Var%..............	8,713.02	19,198.55	152,563.34	219,939.80	172,851.02	245,374.15
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/01/15 1.625%.........................	338,541.67	169,270.84	3,723,958.33	169,270.84	4,062,500.00	169,270.84
First Mortgage Bond due 11/01/20 3.250%.........................	1,354,166.67	677,083.34	14,895,833.33	677,083.34	16,250,000.00	677,083.34
First Mortgage Bond due 11/01/40 5.125%.........................	3,203,125.00	1,601,562.50	35,234,375.00	1,601,562.50	38,437,500.00	1,601,562.50
Fidelia/PPL..	-	3,048,256.29	-	64,015,302.78	-	70,111,815.27
Total..	5,076,988.94	5,736,399.90	56,169,422.37	69,303,536.73	61,310,327.86	75,638,411.79
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense..................................	255,098.40	165,118.84	2,867,790.46	345,460.80	3,106,454.07	363,472.91
Amortization of Loss on Reacquired Debt...............................	50,414.39	50,414.39	554,558.29	554,403.11	604,972.68	604,786.20
Total..	305,512.79	215,533.23	3,422,348.75	899,863.91	3,711,426.75	968,259.11
Other Interest Charges						
Customers' Deposits..	107,464.41	102,308.70	1,250,074.83	1,256,211.57	1,357,433.13	1,375,282.59
Other Tax Deficiencies..	18,358.75	-	18,358.75	83,145.07	22,854.75	83,145.07
Interest on DSM Cost Recovery...	1,269.33	1,149.77	10,519.33	17,126.08	11,773.94	17,725.37
Interest on Debt to Associated Companies..............................	237.86	10,340.02	6,321.35	125,882.77	7,481.99	127,367.46
AFUDC Borrowed Funds..	(2,001.80)	(82,830.32)	(12,379.48)	(885,894.25)	(95,082.16)	(980,162.23)
Other Interest Expense..	253,065.84	155,224.49	3,716,890.47	1,878,962.12	4,200,716.28	2,034,459.73
Total..	378,394.39	186,192.66	4,989,785.25	2,475,433.36	5,505,177.93	2,657,817.99
Total Interest..	$ 5,760,896.12	$ 6,138,125.79	$ 64,581,556.37	$ 72,678,834.00	$ 70,526,932.54	$ 79,264,488.89

December 22, 2011

Kentucky Utilities Company
Analysis of Taxes Charged and Accrued
November 30, 2011

Kind of Taxes	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year
Taxes Charged to Accounts 408.1 and 409.1...........				
Property Taxes..	$ 1,549,833.00	$ 708,194.01	$ 17,048,162.77	$ 9,790,134.11
Unemployment..	2,881.16	(18,113.65)	98,422.49	131,091.72
FICA..	504,908.51	147,661.20	6,587,035.47	6,300,165.12
Public Service Commission Fee..............................	168,112.85	157,659.37	1,786,520.52	1,726,042.63
Federal Income..	6,848,150.40	5,745,607.58	11,298,695.57	54,072,293.78
State Income...	1,248,905.55	1,047,831.17	7,118,075.05	11,200,095.74
Miscellaneous..	19,433.59	5,267.45	87,887.97	79,013.81
Total Charged to Operating Expense..........	10,342,225.06	7,794,107.13	44,024,799.84	83,298,836.91
Taxes Charged to Other Accounts..........................	506,061.08	(5,566,860.94)	3,651,473.06	8,636,360.24
Taxes Accrued on Intercompany Accounts............	(31,998.31)	(239,455.79)	(2,290,170.80)	(2,824,188.84)
Total Taxes Charged.................................	$ 10,816,287.83	$ 1,987,790.40	$ 45,386,102.10	$ 89,111,008.31

Analysis of Taxes Accrued - Account 236

Kind of Taxes	Taxes Accrued At Beginning Of Year	Accruals To Date This Year	Payments To Date This Year	Taxes Accrued At End Of Month
Property Taxes..	$ 8,399,528.00	$ 17,049,999.77	$ 8,933,104.25	$ 16,516,423.52
Unemployment..	75,728.12	60,262.84	135,463.57	527.39
FICA..	639,011.24	5,643,338.82	5,715,136.69	567,213.37
Federal Income..	12,876,014.95	11,001,269.09	5,940,477.00	17,936,807.04
State Income...	2,021,178.48	7,514,716.12	7,759,855.00	1,776,039.60
Kentucky Sales and Use Tax..................................	581,659.33	4,001,128.68	4,023,095.04	559,692.97
Miscellaneous..	21,662.86	115,386.78	125,615.57	11,434.07
Totals...	$ 24,614,782.98	$ 45,386,102.10	$ 32,632,747.12	$ 37,368,137.96

December 22, 2011

Kentucky Utilities Company
Summary of Utility Plant
November 30, 2011

		Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101	**Utility Plant in Service**						
	Electric						
	Electric Distribution.................................	$ 1,312,664,325.73	$ 75,251,605.39	$ (16,376,502.82)	$ 787,154.19	$ 59,662,256.76	$ 1,372,326,582.49
	Electric General Plant..............................	125,243,994.19	14,602,489.10	(4,184,627.91)	(787,154.19)	9,630,707.00	134,874,701.19
	Electric Hydro Production.......................	16,848,655.18	300,776.20	(15,190.72)	-	285,585.48	17,134,240.66
	Electric Intangible Plant...........................	49,640,906.77	8,491,507.87	(1,381,084.50)	-	7,110,423.37	56,751,330.14
	Electric Other Production........................	519,412,128.33	8,564,096.91	(2,076,777.74)	-	6,487,319.17	525,899,447.50
	Electric Steam Production.......................	1,814,421,935.78	731,034,952.07	(11,084,494.66)	124,492,063.50	844,442,520.91	2,658,864,456.69
	Electric Transmission...............................	552,965,733.49	24,102,744.03	(2,739,486.48)	-	21,363,257.55	574,328,991.04
	Total 101 Accounts..................................	4,391,197,679.47	862,348,171.57	(37,858,164.83)	124,492,063.50	948,982,070.24	5,340,179,749.71
102	**Electric Plant Purchased or Sold**						
	Electric						
	Electric Steam...	483,341.17	-	-	-	-	483,341.17
	Total 102001	483,341.17	-	-	-	-	483,341.17
105	**Plant Held for Future Use**						
	Electric						
	Electric Distribution.................................	792,599.21				-	792,599.21
	Electric Steam...	120,828,152.53	-	-	(120,828,152.53)	(120,828,152.53)	-
	Total 105001..	121,620,751.74	-	-	(120,828,152.53)	(120,828,152.53)	792,599.21
106	**Completed Construction Not Classified**						
	Electric						
	Electric Distribution.................................	36,610,963.62	(7,840,056.82)	-	-	(7,840,056.82)	28,770,906.80
	Electric General Plant..............................	769,342.30	5,084,812.08	-	-	5,084,812.08	5,854,154.38
	Electric Hydro Production.......................	-	18,076.75	-	-	18,076.75	18,076.75
	Electric Intangible Plant...........................	2,685,464.69	247,450.29	-	-	247,450.29	2,932,914.98
	Electric Other Production........................	3,737,695.33	(3,472,595.76)	-	-	(3,472,595.76)	265,099.57
	Electric Steam Production.......................	910,748,505.16	(5,020,440.56)	-	-	(5,020,440.56)	905,728,064.60
	Electric Transmission...............................	74,497,274.43	5,891,398.76	-	-	5,891,398.76	80,388,673.19
	Total 106 Accounts..................................	1,029,049,245.53	(5,091,355.26)	-	-	(5,091,355.26)	1,023,957,890.27
121	**Nonutility Property**						
	Common						
	Non Utility Property................................	179,120.94	-	-	-	-	179,120.94
	Total 121001	179,120.94	-	-	-	-	179,120.94
107	**Construction Work In Progress**						
	Electric						
	Electric..	954,430,277.48	(602,182,790.64)	-	-	(602,182,790.64)	352,247,486.84
	Total 107001..	954,430,277.48	(602,182,790.64)	-	-	(602,182,790.64)	352,247,486.84
	Total Plant (Non-CWIP)................................	5,542,530,138.85	857,256,816.31	(37,858,164.83)	3,663,910.97	823,062,562.45	6,365,592,701.30
	Total Plant + CWIP..	6,496,960,416.33	255,074,025.67	(37,858,164.83)	3,663,910.97	220,879,771.81	6,717,840,188.14
	Total Plant + CWIP - Nonutility (BS)............	$ 6,496,781,295.39	$ 255,074,025.67	$ (37,858,164.83)	$ 3,663,910.97	$ 220,879,771.81	$ 6,717,661,067.20

December 22, 2011

Kentucky Utilities Company
Summary of Utility Plant - Reserve for Depreciation of Utility Plant
November 30, 2011

	Beginning Balance	Accruals	Retirements	Transfers/ Adjustments	ARO Settlements	RWIP Transfers Out	Cost of Removal	Salvage	Other Credits	Ending Balance
Life Reserve										
Electric Distribution......................................	$ (398,692,068.83)	$ (25,394,913.69)	$ 16,376,502.82	$ (187,351.34)	$ -	$ -	$ -	$ -	$ -	$ (407,897,831.04)
Electric Distribution - ARO..........................	(790.87)	(4,063.94)	-	-	-	-	-	-	-	(4,854.81)
Electric General Plant..................................	(57,721,732.75)	(5,707,069.30)	4,184,627.91	181,344.61	-	-	-	-	-	(59,062,829.53)
Electric Hydro Production............................	(7,765,077.65)	(109,597.41)	15,190.72	-	-	-	-	-	-	(7,859,484.34)
Electric Hydro Production - ARO................	(121.57)	(891.88)	-	-	-	-	-	-	-	(1,013.45)
Electric Other Production.............................	(160,412,820.60)	(15,323,831.53)	2,076,777.74	-	-	-	-	-	-	(173,659,874.39)
Electric Other Production - ARO.................	(84.76)	(622.27)	-	-	-	-	-	-	-	(707.03)
Electric Steam Production............................	(1,067,997,942.05)	(81,546,733.10)	11,027,799.74	(282,823.63)	-	-	-	-	-	(1,138,799,699.04)
Electric Steam Production - ARO................	(485,952.30)	(2,761,869.76)	56,694.92	(105,352.11)	-	-	-	-	-	(3,296,479.25)
Electric Transmission...................................	(211,361,531.11)	(8,545,984.93)	2,739,486.48	-	-	-	-	-	-	(217,168,029.56)
Electric Transmission - ARO.......................	(156.99)	(1,151.69)	-	-	-	-	-	-	-	(1,308.68)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(1,904,438,279.48)	(139,396,729.50)	36,477,080.33	(394,182.47)	-	-	-	-	-	(2,007,752,111.12)
Cost of Removal										
Electric Distribution......................................	(195,818,054.42)	(7,439,871.30)	-	45,494.52	-	-	3,954,089.46	-	-	(199,258,341.74)
Electric General Plant..................................	207,510.70	(41,850.15)	-	(0.02)	-	-	88,867.31	-	-	254,527.84
Electric Hydro Production............................	(374,056.75)	(4,769.30)	-	-	-	-	29,260.00	-	-	(349,566.05)
Electric Other Production.............................	(3,174,464.89)	(821,051.18)	-	-	-	-	498,253.84	-	-	(3,497,262.23)
Electric Steam Production............................	(113,988,699.33)	(23,100,489.46)	-	282,823.63	-	-	2,580,229.40	-	-	(134,226,135.76)
Electric Transmission...................................	(137,175,896.62)	(2,581,291.12)	-	-	-	-	2,956,516.51	-	-	(136,800,671.23)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(450,323,661.31)	(33,989,322.51)	-	328,318.13	-	-	10,107,216.52	-	-	(473,877,449.17)
Salvage										
Electric Distribution......................................	48,221,606.07	1,815,319.56	-	-	-	-	-	(269,167.53)	-	49,767,758.10
Electric General Plant..................................	149,758.57	-	-	-	-	-	-	(12,678.93)	-	137,079.64
Electric Hydro Production............................	46,518.69	-	-	-	-	-	-	-	-	46,518.69
Electric Other Production.............................	618,891.61	-	-	-	-	-	-	-	-	618,891.61
Electric Steam Production............................	20,938,580.66	4,273,102.26	-	-	-	-	-	(1,382,786.55)	-	23,828,896.37
Electric Transmission...................................	23,009,336.80	598,892.52	-	-	-	-	-	(31,874.47)	-	23,576,354.85
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	92,984,692.40	6,687,314.34	-	-	-	-	-	(1,696,507.48)	-	97,975,499.26
Total Reserves										
Electric Distribution......................................	(546,288,517.18)	(31,019,465.43)	16,376,502.82	(141,856.82)	-	-	3,954,089.46	(269,167.53)	-	(557,388,414.68)
Electric Distribution - ARO..........................	(790.87)	(4,063.94)	-	-	-	-	-	-	-	(4,854.81)
Electric General Plant..................................	(57,364,463.48)	(5,748,919.45)	4,184,627.91	181,344.59	-	-	88,867.31	(12,678.93)	-	(58,671,222.05)
Electric Hydro Production............................	(8,092,615.71)	(114,366.71)	15,190.72	-	-	-	29,260.00	-	-	(8,162,531.70)
Electric Hydro Production - ARO................	(121.57)	(891.88)	-	-	-	-	-	-	-	(1,013.45)
Electric Other Production.............................	(162,968,393.88)	(16,144,882.71)	2,076,777.74	-	-	-	498,253.84	-	-	(176,538,245.01)
Electric Other Production - ARO.................	(84.76)	(622.27)	-	-	-	-	-	-	-	(707.03)
Electric Steam Production............................	(1,161,048,060.72)	(100,374,120.30)	11,027,799.74	-	-	-	2,580,229.40	(1,382,786.55)	-	(1,249,196,938.43)
Electric Steam Production - ARO................	(485,952.30)	(2,761,869.76)	56,694.92	(105,352.11)	-	-	-	-	-	(3,296,479.25)
Electric Transmission...................................	(325,528,090.93)	(10,528,383.53)	2,739,486.48	-	-	-	2,956,516.51	(31,874.47)	-	(330,392,345.94)
Electric Transmission - ARO.......................	(156.99)	(1,151.69)	-	-	-	-	-	-	-	(1,308.68)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(2,261,777,248.39)	(166,698,737.67)	36,477,080.33	(65,864.34)	-	-	10,107,216.52	(1,696,507.48)	-	(2,383,654,061.03)
Retirement Work in Process										
Electric..	13,605,672.01		-	14,675.52	(161,732.61)	(8,248,976.43)	12,993,598.39	(732,461.41)	(472,326.54)	16,998,448.93
	13,605,672.01	-	-	14,675.52	(161,732.61)	(8,248,976.43)	12,993,598.39	(732,461.41)	(472,326.54)	16,998,448.93
YTD ACTIVITY	(2,248,171,576.38)	(166,698,737.67)	36,477,080.33	(51,188.82)	(161,732.61)	(8,248,976.43)	23,100,814.91	(2,428,968.89)	(472,326.54)	(2,366,655,612.10)
Amortization										
Electric..	(13,755,205.98)	(6,613,562.88)	1,381,084.50	-	-	-	-	-	-	(18,987,684.36)
	(13,755,205.98)	(6,613,562.88)	1,381,084.50	-	-	-	-	-	-	(18,987,684.36)
Depreciation & Amortization Total										
Depreciation & Amortization Total...............	(2,261,926,782.36)	(173,312,300.55)	37,858,164.83	(51,188.82)	(161,732.61)	(8,248,976.43)	23,100,814.91	(2,428,968.89)	(472,326.54)	(2,385,643,296.46)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)...............	$ 4,234,854,513.03									$ 4,332,017,770.74

December 22, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of November 30, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues....................................	$ 117,741,030.82	$ -	$ 117,741,030.82
Rate Refunds..	-	-	-
Total Operating Revenues....................................	117,741,030.82	-	117,741,030.82
Fuel for Electric Generation.....................................	38,916,400.82	-	38,916,400.82
Power Purchased...	6,841,266.72	-	6,841,266.72
Other Operation Expenses.......................................	18,620,233.99	-	18,620,233.99
Maintenance..	8,771,745.72	-	8,771,745.72
Depreciation..	15,367,965.42	-	15,367,965.42
Amortization Expense...	657,712.91	-	657,712.91
Regulatory Credits...	(507,360.58)	-	(507,360.58)
Taxes			
Federal Income..	6,848,150.40	-	6,848,150.40
State Income..	1,248,905.55	-	1,248,905.55
Deferred Federal Income - Net..............................	83,583.78	(22,475.59)	61,108.19
Deferred State Income - Net..................................	(11,910.45)	(4,098.89)	(16,009.34)
Property and Other..	2,245,169.11	-	2,245,169.11
Loss (Gain) from Disposition of Allowances...........	-	-	-
Accretion Expense...	251,742.18	-	251,742.18
Total Operating Expenses.....................................	99,333,605.57	(26,574.48)	99,307,031.09
Net Operating Income...	18,407,425.25	26,574.48	18,433,999.73
Other Income Less Deductions			
Amortization of Investment Tax Credit.............	233,343.00	-	233,343.00
Other Income Less Deductions...........................	(83,564.67)	(73,840.35)	(157,405.02)
AFUDC - Equity...	6,598.45	-	6,598.45
Total Other Income Less Deductions....................	156,376.78	(73,840.35)	82,536.43
Income Before Interest Charges............................	18,563,802.03	(47,265.87)	18,516,536.16
Interest on Long-Term Debt....................................	5,076,988.94	(5,525.49)	5,071,463.45
Amortization of Debt Expense - Net.........................	305,512.79	-	305,512.79
Other Interest Expenses...	380,396.19	-	380,396.19
AFUDC - Borrowed Funds......................................	(2,001.80)	-	(2,001.80)
Total Interest Charges...	5,760,896.12	(5,525.49)	5,755,370.63
Net Income..	$ 12,802,905.91	$ (41,740.38)	$ 12,761,165.53

December 22, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of November 30, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 1,417,752,676.31	$ -	$ 1,417,752,676.31
Rate Refunds	-	-	-
Total Operating Revenues	1,417,752,676.31	-	1,417,752,676.31
Fuel for Electric Generation	481,065,680.13	-	481,065,680.13
Power Purchased	97,952,666.51	-	97,952,666.51
Other Operation Expenses	213,026,327.27	31,612.30	213,057,939.57
Maintenance	107,461,242.16	-	107,461,242.16
Depreciation	166,444,465.23	-	166,444,465.23
Amortization Expense	6,613,562.88	-	6,613,562.88
Regulatory Credits	(5,342,900.74)	-	(5,342,900.74)
Taxes			
Federal Income	11,298,695.57	-	11,298,695.57
State Income	7,118,075.05	-	7,118,075.05
Deferred Federal Income - Net	75,404,168.12	(38,933.62)	75,365,234.50
Deferred State Income - Net	6,429,652.60	(7,100.36)	6,422,552.24
Property and Other	25,608,029.22	-	25,608,029.22
Loss (Gain) from Disposition of Allowances	(3,293.39)	-	(3,293.39)
Accretion Expense	2,574,301.20	-	2,574,301.20
Total Operating Expenses	1,195,650,671.81	(14,421.68)	1,195,636,250.13
Net Operating Income	222,102,004.50	14,421.68	222,116,426.18
Other Income Less Deductions			
Amortization of Investment Tax Credit	2,453,062.00	-	2,453,062.00
Other Income Less Deductions	1,060,276.18	713,751.09	1,774,027.27
AFUDC - Equity	40,766.48	-	40,766.48
Total Other Income Less Deductions	3,554,104.66	713,751.09	4,267,855.75
Income Before Interest Charges	225,656,109.16	728,172.77	226,384,281.93
Interest on Long-Term Debt	56,169,422.37	(60,780.40)	56,108,641.97
Amortization of Debt Expense - Net	3,422,348.75	-	3,422,348.75
Other Interest Expenses	5,002,164.73	-	5,002,164.73
AFUDC - Borrowed Funds	(12,379.48)	-	(12,379.48)
Total Interest Charges	64,581,556.37	(60,780.40)	64,520,775.97
Net Income	$ 161,074,552.79	$ 788,953.17	$ 161,863,505.96

December 22, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of November 30, 2011

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,498,556,521.70	$ 15,999,114.75	$ (1,402,430,954.73)	$ (15,126,903.94)	$ 96,125,566.97	$ 872,210.81
Add						
Net Income for Period..	12,802,905.91	-	(41,740.38)	-	12,761,165.53	-
Deductions:						
Common Dividends						
Common Stock Without Par Value..................	(36,000,000.00)	-	-	-	(36,000,000.00)	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc..	(93,007.00)	93,007.00	73,840.35	(73,840.35)	(19,166.65)	19,166.65
Balance at End of Period	$ 1,475,266,420.61	$ 16,092,121.75	$ (1,402,398,854.76)	$ (15,200,744.29)	$ 72,867,565.85	$ 891,377.46
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings................		16,092,121.75		(15,200,744.29)		891,377.46
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.........................		$ 6,259,835.36		$ (5,913,089.53)		$ 346,745.83

December 22, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of November 30, 2011

Retained Earnings and Undistributed Earnings	Year to Date without Purchase Accounting: Retained Earnings	Year to Date without Purchase Accounting: Undistributed Subsidiary Earnings	Year to Date Purchase Accounting: Retained Earnings	Year to Date Purchase Accounting: Undistributed Subsidiary Earnings	Year to Date Combined: Retained Earnings	Year to Date Combined: Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,439,351,593.82	$ 14,432,395.75	$ (1,404,000,051.78)	$ (14,388,500.44)	$ 35,351,542.04	$ 43,895.31
Add						
Net Income for Period ………………………………	161,074,552.79	-	788,953.17	-	161,863,505.96	-
Deductions:						
Common Dividends						
Common Stock Without Par Value...................	(123,500,000.00)		-		(123,500,000.00)	
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc……………………….…………	(1,659,726.00)	1,659,726.00	812,243.85	(812,243.85)	(847,482.15)	847,482.15
Balance at End of Period …...……………………………	$ 1,475,266,420.61	$ 16,092,121.75	$ (1,402,398,854.76)	$ (15,200,744.29)	$ 72,867,565.85	$ 891,377.46
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings…………		16,092,121.75		(15,200,744.29)		891,377.46
Statutory Tax Rate…...…………………………………		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary…...………………		$ 6,259,835.36		$ (5,913,089.53)		$ 346,745.83

December 22, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of November 30, 2011

Retained Earnings and Undistributed Earnings	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,414,639,467.15	$ 13,996,368.75	$ (1,404,070,533.21)	$ (14,240,819.75)	$ 10,568,933.94	$ (244,451.00)
Add						
Net Income for Period...	186,222,706.46	-	711,753.91	-	186,934,460.37	-
Purchase Accounting Deductions:					-	-
Deductions:						
Common Dividends						
Common Stock Without Par Value...................	(123,500,000.00)		-		(123,500,000.00)	
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	(2,095,753.00)	2,095,753.00	959,924.54	(959,924.54)	(1,135,828.46)	1,135,828.46
Balance at End of Period	$ 1,475,266,420.61	$ 16,092,121.75	$ (1,402,398,854.76)	$ (15,200,744.29)	$ 72,867,565.85	$ 891,377.46

Deferred Taxes Related to Undistributed Subsidiary Earnings			
Balance of Undistributed Subsidiary Earnings................	16,092,121.75	(15,200,744.29)	891,377.46
Statutory Tax Rate...	38.9%	38.9%	38.9%
Deferred Taxes on Equity in Subsidiary..........................	$ 6,259,835.36	$ (5,913,089.53)	$ 346,745.83

Combined Balance of Retained Earnings	12 MONTHS 11/30/2011	12 MONTHS 11/30/2010
Retained Earnings at Beginning of Period.......................	$ 10,324,482.94	$ 1,305,065,504.89
Net Income for Period	186,934,460.37	159,342,544.90
FIN 48 Adjustment...	-	-
Subtotal..	197,258,943.31	1,464,408,049.79
Deduct		
Purchase Accounting Adjustment...............................	-	1,404,083,566.85
Dividends on Common Stock.....................................	123,500,000.00	50,000,000.00
Retained Earnings at End of Period.................................	$ 73,758,943.31	$ 10,324,482.94

December 22, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of November 30, 2011

Assets	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 6,717,661,067.20	$ -	$ 6,717,661,067.20
Less Reserves for Depreciation and Amortization.....	2,385,643,296.46	-	2,385,643,296.46
Total...	4,332,017,770.74	-	4,332,017,770.74
Investments			
Electric Energy, Inc..	13,357,842.55	16,761,758.46	30,119,601.01
Ohio Valley Electric Corporation.............................	250,000.00	-	250,000.00
Nonutility Property - Less Reserve...........................	179,154.72	-	179,154.72
Special Funds..	-	-	-
Total...	13,786,997.27	16,761,758.46	30,548,755.73
Current and Accrued Assets			
Cash..	33,369,232.56	-	33,369,232.56
Special Deposits..	-	-	-
Temporary Cash Investments.................................	61,337,721.56	-	61,337,721.56
Accounts Receivable-Less Reserve........................	143,602,834.36	-	143,602,834.36
Accounts Receivable from Assoc Companies..........	2,281.36	-	2,281.36
Materials & Supplies-At Average Cost			
Fuel..	98,217,300.29	-	98,217,300.29
Plant Materials & Operating Supplies..................	34,369,554.14	-	34,369,554.14
Stores Expense..	10,186,164.04	-	10,186,164.04
Allowance Inventory..	460,964.54	-	460,964.54
Prepayments..	6,481,180.70	-	6,481,180.70
Miscellaneous Current & Accrued Assets..............	0.01	-	0.01
Total...	388,027,233.56	-	388,027,233.56
Deferred Debits and Other			
Unamortized Debt Expense......................................	21,783,072.56	(4,427,808.40)	17,355,264.16
Unamortized Loss on Bonds....................................	11,825,531.76	-	11,825,531.76
Accumulated Deferred Income Taxes.......................	88,863,654.64	63,325,811.92	152,189,466.56
Deferred Regulatory Assets.....................................	274,713,424.52	12,242,739.16	286,956,163.68
Other Deferred Debits..	45,221,104.51	143,918,469.50	189,139,574.01
Goodwill...	-	607,404,368.23	607,404,368.23
Total...	442,406,787.99	822,463,580.41	1,264,870,368.40
Total Assets..	$ 5,176,238,789.56	$ 839,225,338.87	$ 6,015,464,128.43

December 22, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of November 30, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Proprietary Capital			
Common Stock..	$ 308,139,977.56	$ -	$ 308,139,977.56
Less: Common Stock Expense.....................................	321,288.87	-	321,288.87
Paid-In Capital..	315,858,083.00	2,032,588,750.94	2,348,446,833.94
Other Comprehensive Income.....................................	(2,456,676.43)	1,990,823.26	(465,853.17)
Retained Earnings..	1,475,266,420.61	(1,402,398,854.76)	72,867,565.85
Unappropriated Undistributed Subsidiary Earnings....	16,092,121.75	(15,200,744.29)	891,377.46
Total Proprietary Capital..	2,112,578,637.62	616,979,975.15	2,729,558,612.77
Pollution Control Bonds - Net of Reacquired Bonds...	350,779,405.00	1,089,623.62	351,869,028.62
First Mortgage Bonds..	1,489,759,218.75	-	1,489,759,218.75
Total Long-Term Debt...	1,840,538,623.75	1,089,623.62	1,841,628,247.37
Total Capitalization..	3,953,117,261.37	618,069,598.77	4,571,186,860.14
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Accounts Payable...	96,368,319.57	-	96,368,319.57
Accounts Payable to Associated Companies................	29,090,154.96	-	29,090,154.96
Customer Deposits...	23,058,149.37	-	23,058,149.37
Taxes Accrued..	37,368,137.96	-	37,368,137.96
Interest Accrued...	6,272,253.56	-	6,272,253.56
Dividends Declared..	36,000,000.00	-	36,000,000.00
Miscellaneous Current and Accrued Liabilities...........	16,957,328.53	-	16,957,328.53
Total..	245,114,343.95	-	245,114,343.95
Deferred Credits and Other			
Accumulated Deferred Income Taxes..........................	531,911,216.48	69,422,339.84	601,333,556.32
Investment Tax Credit..	101,641,107.32	-	101,641,107.32
Regulatory Liabilities...	112,488,037.07	143,918,469.50	256,406,506.57
Customer Advances for Construction..........................	3,166,933.71	-	3,166,933.71
Asset Retirement Obligations......................................	60,183,309.93	-	60,183,309.93
Other Deferred Credits...	32,647,513.35	7,814,930.76	40,462,444.11
Miscellaneous Long-Term Liabilities..........................	2,747,598.99	-	2,747,598.99
Accum Provision for Postretirement Benefits.............	133,221,467.39	-	133,221,467.39
Total..	978,007,184.24	221,155,740.10	1,199,162,924.34
Total Liabilities and Stockholders' Equity.........................	$ 5,176,238,789.56	$ 839,225,338.87	$ 6,015,464,128.43

December 22, 2011

KENTUCKY UTILITIES COMPANY

Financial Reports

October 31, 2011

Index
Financial and Operating Reports

Kentucky Utilities Company
October 31, 2011

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2011 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows, unless otherwise noted.

Kentucky Utilities Company
Comparative Statement of Income
October 31, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 109,334,689.01	$ 101,714,548.73	$ 7,620,140.28	7.49
Rate Refunds	-	6.12	(6.12)	(100.00)
Total Operating Revenues	109,334,689.01	101,714,554.85	7,620,134.16	7.49
Fuel for Electric Generation	36,322,228.62	26,145,610.81	10,176,617.81	38.92
Power Purchased	8,143,019.97	12,361,226.41	(4,218,206.44)	(34.12)
Other Operation Expenses	18,299,968.94	15,424,201.23	2,875,767.71	18.64
Maintenance	9,234,799.44	11,995,339.81	(2,760,540.37)	(23.01)
Depreciation	15,338,724.10	12,108,789.84	3,229,934.26	26.67
Amortization Expense	633,804.87	549,052.35	84,752.52	15.44
Regulatory Credits	(506,291.71)	(219,681.93)	(286,609.78)	(130.47)
Taxes				
Federal Income	5,980,891.91	18,337,562.75	(12,356,670.84)	(67.38)
State Income	(216,846.15)	5,275,008.54	(5,491,854.69)	(104.11)
Deferred Federal Income - Net	(183,443.31)	(15,447,486.50)	15,264,043.19	98.81
Deferred State Income - Net	1,302,323.04	(4,454,554.35)	5,756,877.39	129.24
Property and Other	2,274,856.24	2,032,184.96	242,671.28	11.94
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	-	-	-	-
Accretion Expense	250,673.41	162,146.50	88,526.91	54.60
Total Operating Expenses	96,874,709.37	84,269,400.42	12,605,308.95	14.96
Net Operating Income	12,459,979.64	17,445,154.43	(4,985,174.79)	(28.58)
Other Income Less Deductions				
Amortization of Investment Tax Credit	233,343.00	5,925.00	227,418.00	3,838.28
Other Income Less Deductions	(377,414.24)	64,062.87	(441,477.11)	(689.13)
AFUDC - Equity	6,036.17	104,384.03	(98,347.86)	(94.22)
Total Other Income Less Deductions	(138,035.07)	174,371.90	(312,406.97)	(179.16)
Income Before Interest Charges	12,321,944.57	17,619,526.33	(5,297,581.76)	(30.07)
Interest on Long-Term Debt	5,093,536.87	6,346,464.01	(1,252,927.14)	(19.74)
Amortization of Debt Expense - Net	340,508.13	68,470.36	272,037.77	397.31
Other Interest Expenses	487,646.00	270,342.04	217,303.96	80.38
AFUDC - Borrowed Funds	(1,831.33)	(82,598.97)	80,767.64	97.78
Total Interest Charges	5,919,859.67	6,602,677.44	(682,817.77)	(10.34)
Net Income	$ 6,402,084.90	$ 11,016,848.89	$ (4,614,763.99)	(41.89)

November 21, 2011

Kentucky Utilities Company
Comparative Statement of Income
October 31, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 1,300,011,645.49	$ 1,248,568,509.67	$ 51,443,135.82	4.12
Rate Refunds	-	(632,383.92)	632,383.92	100.00
Total Operating Revenues	1,300,011,645.49	1,247,936,125.75	52,075,519.74	4.17
Fuel for Electric Generation	442,149,279.31	417,290,298.00	24,858,981.31	5.96
Power Purchased	91,111,399.79	146,985,632.74	(55,874,232.95)	(38.01)
Other Operation Expenses	194,406,093.28	178,868,863.49	15,537,229.79	8.69
Maintenance	98,689,496.44	84,729,502.74	13,959,993.70	16.48
Depreciation	151,076,499.81	114,536,854.05	36,539,645.76	31.90
Amortization Expense	5,955,849.97	5,492,351.98	463,497.99	8.44
Regulatory Credits	(4,835,540.16)	(4,216,028.02)	(619,512.14)	(14.69)
Taxes				
Federal Income	4,450,545.17	48,326,686.20	(43,876,141.03)	(90.79)
State Income	5,869,169.50	10,152,264.57	(4,283,095.07)	(42.19)
Deferred Federal Income - Net	75,320,584.34	18,307,159.67	57,013,424.67	311.43
Deferred State Income - Net	6,441,563.05	2,754,931.60	3,686,631.45	133.82
Property and Other	23,362,860.11	17,025,779.01	6,337,081.10	37.22
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	(3,293.39)	(44,023.81)	40,730.42	92.52
Accretion Expense	2,322,559.02	3,052,482.10	(729,923.08)	(23.91)
Total Operating Expenses	1,096,317,066.24	1,043,262,754.32	53,054,311.92	5.09
Net Operating Income	203,694,579.25	204,673,371.43	(978,792.18)	(0.48)
Other Income Less Deductions				
Amortization of Investment Tax Credit	2,219,719.00	59,250.00	2,160,469.00	3,646.36
Other Income Less Deductions	1,143,840.85	1,530,432.69	(386,591.84)	(25.26)
AFUDC - Equity	34,168.03	312,468.79	(278,300.76)	(89.07)
Total Other Income Less Deductions	3,397,727.88	1,902,151.48	1,495,576.40	78.63
Income Before Interest Charges	207,092,307.13	206,575,522.91	516,784.22	0.25
Interest on Long-Term Debt	51,092,433.43	63,567,136.83	(12,474,703.40)	(19.62)
Amortization of Debt Expense - Net	3,116,835.96	684,330.68	2,432,505.28	355.46
Other Interest Expenses	4,621,768.54	3,092,304.63	1,529,463.91	49.46
AFUDC - Borrowed Funds	(10,377.68)	(803,063.93)	792,686.25	98.71
Total Interest Charges	58,820,660.25	66,540,708.21	(7,720,047.96)	(11.60)
Net Income	$ 148,271,646.88	$ 140,034,814.70	$ 8,236,832.18	5.88

November 21, 2011

Kentucky Utilities Company
Comparative Statement of Income
October 31, 2011

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues.....................................	$ 1,563,785,231.74	$ 1,477,590,421.70	$ 86,194,810.04	5.83
Rate Refunds..	-	(1,101,614.71)	1,101,614.71	100.00
Total Operating Revenues......................................	1,563,785,231.74	1,476,488,806.99	87,296,424.75	5.91
Fuel for Electric Generation......................................	520,943,169.44	490,029,785.96	30,913,383.48	6.31
Power Purchased...	118,747,704.32	178,038,734.94	(59,291,030.62)	(33.30)
Other Operation Expenses..	232,184,457.56	213,955,882.17	18,228,575.39	8.52
Maintenance..	121,773,978.50	108,660,423.40	13,113,555.10	12.07
Depreciation..	175,821,686.45	136,028,456.69	39,793,229.76	29.25
Amortization Expense...	7,066,961.91	6,601,061.26	465,900.65	7.06
Regulatory Credits..	(5,769,069.49)	(4,623,636.38)	(1,145,433.11)	(24.77)
Taxes				
Federal Income...	17,783,308.25	57,392,083.59	(39,608,775.34)	(69.01)
State Income...	8,473,297.44	10,570,936.30	(2,097,638.86)	(19.84)
Deferred Federal Income - Net...............................	79,288,876.42	12,965,587.19	66,323,289.23	511.53
Deferred State Income - Net...................................	6,997,669.63	3,380,661.72	3,617,007.91	106.99
Property and Other...	26,230,560.07	19,277,988.00	6,952,572.07	36.06
Investment Tax Credit..	-	2,958,591.69	(2,958,591.69)	(100.00)
Loss (Gain) from Disposition of Allowances...........	(16,020.32)	(44,023.81)	28,003.49	63.61
Accretion Expense..	2,768,981.86	3,410,600.26	(641,618.40)	(18.81)
Total Operating Expenses......................................	1,312,295,562.04	1,238,603,132.98	73,692,429.06	5.95
Net Operating Income...	251,489,669.70	237,885,674.01	13,603,995.69	5.72
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	2,231,569.00	91,634.50	2,139,934.50	2,335.29
Other Income Less Deductions...........................	671,322.08	(356,017.52)	1,027,339.60	288.56
AFUDC - Equity...	242,851.28	752,676.01	(509,824.73)	(67.74)
Total Other Income Less Deductions.....................	3,145,742.36	488,292.99	2,657,449.37	544.23
Income Before Interest Charges.............................	254,635,412.06	238,373,967.00	16,261,445.06	6.82
Interest on Long-Term Debt......................................	61,969,738.82	76,083,191.40	(14,113,452.58)	(18.55)
Amortization of Debt Expense - Net.........................	3,621,447.19	821,113.00	2,800,334.19	341.04
Other Interest Expenses..	5,488,886.88	3,587,579.97	1,901,306.91	53.00
AFUDC - Borrowed Funds.......................................	(175,910.68)	(990,568.14)	814,657.46	82.24
Total Interest Charges..	70,904,162.21	79,501,316.23	(8,597,154.02)	(10.81)
Net Income..	$ 183,731,249.85	$ 158,872,650.77	$ 24,858,599.08	15.65

November 21, 2011

Kentucky Utilities Company
Analysis of Retained Earnings
October 31, 2011

Retained Earnings and Undistributed Earnings	Current Month Total Retained Earnings	Current Month Undistributed Subsidiary Earnings	Year to Date Total Retained Earnings	Year to Date Undistributed Subsidiary Earnings	Year Ended Current Month Total Retained Earnings	Year Ended Current Month Undistributed Subsidiary Earnings
Balance at Beginning of Period..	$ 1,491,575,229.80	$ 16,578,321.75	$ 1,439,351,593.82	$ 14,432,395.75	$ 1,404,083,566.85	$ 14,240,819.75
Add:						
Net Income for Period..	6,402,084.90	-	148,271,646.88	-	183,731,249.85	-
Deduct:						
Common Dividends						
Common Stock Without Par Value	-	-	(87,500,000.00)	-	(87,500,000.00)	-
EE Inc..	579,207.00	(579,207.00)	(1,566,719.00)	1,566,719.00	(1,758,295.00)	1,758,295.00
Balance at End of Period..	$ 1,498,556,521.70	$ 15,999,114.75	$ 1,498,556,521.70	$ 15,999,114.75	$ 1,498,556,521.70	$ 15,999,114.75
Deferred Taxes Related to Undistributed Subsidiary Earnings		-		-		-
Balance of Undistributed Subsidiary Earnings.............................		15,999,114.75		15,999,114.75		15,999,114.75
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.......................................		$ 6,223,655.64		$ 6,223,655.64		$ 6,223,655.64

November 21, 2011

Kentucky Utilities Company
Comparative Balance Sheets as of October 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,689,993,192.69	$ 6,422,892,393.59
Less: Reserves for Depreciation and Amortization	2,373,262,876.85	2,255,026,280.85
Total	4,316,730,315.84	4,167,866,112.74
Investments		
Electric Energy, Inc	13,257,506.55	12,278,316.55
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	179,120.94	179,120.94
Total	13,686,627.49	12,707,437.49
Current and Accrued Assets		
Cash	38,368,881.00	4,089,316.42
Special Deposits	91,580.74	-
Temporary Cash Investments	84,580,471.97	269.25
Accounts Receivable-Less Reserve	141,041,770.72	173,568,654.41
Accounts Receivable from Associated Companies	455,305.37	5,093.26
Materials and Supplies-At Average Cost		
Fuel	95,361,449.01	100,493,576.74
Plant Materials and Operating Supplies	33,838,235.20	32,904,785.35
Stores Expense	9,915,258.19	8,537,331.49
Emission Allowances	471,706.71	604,882.03
Prepayments	7,404,467.92	5,568,403.33
Miscellaneous Current and Accrued Assets	99,869.06	151,040.62
Total	411,628,995.89	325,923,352.90
Deferred Debits and Other		
Unamortized Debt Expense	21,939,036.47	4,662,536.01
Unamortized Loss on Bonds	11,875,946.15	12,480,918.83
Accumulated Deferred Income Taxes	80,128,837.66	55,329,162.68
Deferred Regulatory Assets	275,790,726.22	248,688,306.06
Other Deferred Debits	44,953,426.24	42,102,208.93
Total	434,687,972.74	363,263,132.51
Total Assets	$ 5,176,733,911.96	$ 4,869,760,035.64

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	315,858,083.00	315,858,083.00
Other Comprehensive Income	(2,464,005.43)	(1,990,823.26)
Retained Earnings	1,498,556,521.70	1,404,083,566.85
Unappropriated Undistributed Subsidiary Earnings	15,999,114.75	14,240,819.75
Total Proprietary Capital	2,135,768,402.71	2,040,010,335.03
Pollution Control Bonds	350,779,405.00	350,779,405.00
First Mortgage Bonds	1,489,706,281.25	-
LT Notes Payable to Associated Companies	-	1,298,000,000.00
Total Long-Term Debt	1,840,485,686.25	1,648,779,405.00
Total Capitalization	3,976,254,088.96	3,688,789,740.03
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	126,681,954.00
Accounts Payable	108,573,928.06	93,251,390.29
Accounts Payable to Associated Companies	27,179,594.19	85,905,736.80
Customer Deposits	23,087,841.48	22,004,997.93
Taxes Accrued	27,398,823.34	9,876,899.68
Interest Accrued	30,560,526.52	1,251,714.54
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	16,277,382.73	20,987,826.62
Total	233,078,096.32	359,960,519.86
Deferred Credits and Other		
Accumulated Deferred Income Taxes	524,684,542.81	411,964,643.98
Investment Tax Credit	101,874,450.32	104,106,019.32
Regulatory Liabilities	111,397,690.09	43,037,374.23
Customer Advances for Construction	3,160,049.48	2,880,812.65
Asset Retirement Obligations	59,931,567.75	59,512,212.02
Other Deferred Credits	30,374,354.69	9,050,592.54
Miscellaneous Long-Term Liabilities	2,747,598.99	2,544,954.52
Accum Provision for Postretirement Benefits	133,231,472.55	187,913,166.49
Total	967,401,726.68	821,009,775.75
Total Liabilities and Stockholders Equity	$ 5,176,733,911.96	$ 4,869,760,035.64

November 21, 2011

Kentucky Utilities Company
Statement of Capitalization and Short-Term Debt
October 31, 2011

	Authorized Shares	Issued and Outstanding Shares	Issued and Outstanding Amount	Percent of Total Capital
Proprietary Capital				
Common Stock - Without Par...	80,000,000	37,817,878	$ 308,139,977.56	
Less: Common Stock Expense..			321,288.87	
Paid-In Capital..			315,858,083.00	
Other Comprehensive Income...			(2,464,005.43)	
Retained Earnings...			1,498,556,521.70	
Unappropriated Undistributed Subsidiary Earnings.............			15,999,114.75	
Total Proprietary Capital..			2,135,768,402.71	53.71
Long-Term Debt				
Pollution Control Bonds				
Mercer County 2000 Series A due 05/01/23 Var%...........			12,900,000.00	
Carroll County 2002 Series A due 02/01/32 Var%...........			20,930,000.00	
Carroll County 2002 Series B due 02/01/32 Var%...........			2,400,000.00	
Carroll County 2002 Series C due 10/01/32 Var%...........			96,000,000.00	
Mercer County 2002 Series A due 02/01/32 Var%...........			7,400,000.00	
Muhlenburg County 2002 Series A due 02/01/32 Var%...			2,400,000.00	
Carroll County 2004 Series A due 10/01/34 Var%...........			50,000,000.00	
Carroll County 2006 Series B due 10/01/34 Var%...........			54,000,000.00	
Carroll County 2007 Series A due 02/01/26 5.75%..........			17,875,000.00	
Trimble County 2007 Series A due 03/01/37 6.00%.........			8,927,000.00	
Carroll County 2008 Series A due 02/01/32 Var%...........			77,947,405.00	
Total Pollution Control Bonds..			350,779,405.00	8.82
First Mortgage Bonds				
First Mortgage Bond due 11/01/15 1.625%........................			250,000,000.00	
First Mortgage Bond due 11/01/20 3.250%.......................			500,000,000.00	
First Mortgage Bond due 11/01/40 5.125%.......................			750,000,000.00	
Total First Mortgage Bonds..			1,500,000,000.00	37.72
Less: First Mortgage Bonds Debt Discount				
First Mortgage Bond due 11/01/15 1.625%........................			(707,291.68)	
First Mortgage Bond due 11/01/20 3.250%.......................			(1,708,875.00)	
First Mortgage Bond due 11/01/40 5.125%.......................			(7,877,552.07)	
			(10,293,718.75)	(0.25)
Total First Mortgage Bonds - Net of Debt Discount............			1,489,706,281.25	37.47
Total Capitalization...			$ 3,976,254,088.96	100.00

November 21, 2011

Kentucky Utilities Company
Summary Trial Balance
October 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 6,689,993,192.69	$ 6,689,993,192.69
Reserves for Depreciation and Amortization		(2,373,262,876.85)
Depreciation of Plant	(2,354,932,905.40)	
Amortization of Plant	(18,329,971.45)	
Investments		13,686,627.49
Electric Energy, Inc	13,257,506.55	
Ohio Valley Electric Corporation	250,000.00	
Nonutility Property Reserve	179,120.94	
Cash	38,368,881.00	38,368,881.00
Special Deposits		91,580.74
MAN Margin Call	91,580.74	
Temporary Cash Investments	84,580,471.97	84,580,471.97
Accounts Receivable - Less Reserve		141,041,770.72
Customers - Active	69,599,796.25	
Unbilled Revenues	61,865,544.40	
IMPA	2,099,715.98	
IMEA	1,975,226.17	
Mutual Aid	1,086,605.42	
Transmission Sales	1,065,537.36	
Wholesale Sales	959,070.60	
Damage Claims	355,672.33	
Bechtel Liquidated Damages	25,110.00	
Sundry Accounts Receivable	5,078.16	
Other	4,463,941.02	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	7,321,826.09	
Accrual	(5,298,617.36)	
Reserve	(2,174,752.00)	
Recoveries	(2,023,074.54)	
A/R Miscellaneous	(284,909.16)	
Accounts Receivable from Associated Companies		455,305.37
PPL Energy Funding	234,143.34	
LG&E - KU Energy Services/Louisville Gas and Electric Company	221,162.03	
Fuel		95,361,449.01
Coal 1,569,762.04 Tons @ $55.70 MMBtu 35,935,747.50 @ 243.31¢	87,435,571.44	
Fuel Oil 3,107,916 Gallons @ 253.64¢	7,882,792.83	
Gas Pipeline 10,459.80 Mcf @ $4.12	43,084.74	
Plant Materials and Operating Supplies		33,838,235.20
Regular Materials and Supplies	33,249,148.76	
Limestone 68,702.20 Tons @ $8.57	589,086.41	
Other Reagents	0.03	
Stores Expense Undistributed	9,915,258.19	9,915,258.19

November 21, 2011

Kentucky Utilities Company
Summary Trial Balance
October 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Emission Allowances	$ 471,706.71	$ 471,706.71
Prepayments		7,404,467.92
Insurance	2,395,286.29	
Taxes	1,344,902.86	
Lease	619,839.92	
Risk Management and Workers Compensation	75,000.00	
Other	2,969,438.85	
Miscellaneous Current Assets		99,869.06
Derivative Asset - Non-Hedging	99,869.06	
Unamortized Debt Expense		21,939,036.47
Carroll County 2002 Series A due 02/01/32 Var%	83,028.34	
Carroll County 2002 Series B due 02/01/32 Var%	57,705.62	
Carroll County 2002 Series C due 10/01/32 Var%	1,540,679.68	
Mercer County 2002 Series A due 02/01/32 Var%	23,178.40	
Muhlenburg County 2002 Series A due 02/01/32 Var%	64,237.11	
Carroll County 2006 Series B due 10/01/34 Var%	1,098,167.42	
Carroll County 2007 Series A due 02/01/26 5.75%	475,125.27	
Trimble County 2007 Series A due 03/01/37 6.00%	407,149.16	
Carroll County 2008 Series A due 02/01/32 Var%	696,593.37	
First Mortgage Bond due 11/01/15 1.625%	1,848,740.04	
First Mortgage Bond due 11/01/20 3.250%	3,770,066.11	
First Mortgage Bond due 11/01/40 5.125%	7,239,691.18	
Revolving Credit Agreement	4,634,674.77	
Unamortized Loss on Bonds		11,875,946.15
Refinanced and Called Bonds	11,875,946.15	
Accumulated Deferred Income Taxes		80,128,837.66
Federal	67,868,561.79	
State	12,260,275.87	
Regulatory Assets		275,790,726.22
Pension and Postretirement Benefits	117,274,368.11	
ASC 740 - Deferred Taxes	76,771,478.57	
2009 Winter Storm	50,082,163.72	
Asset Retirement Obligations	6,455,532.32	
Virginia Mountain Snowstorm	6,041,670.12	
FERC Jurisdictional Pension Expense	5,705,322.15	
VA Fuel Component Non-Current	4,537,000.00	
MISO Exit Fee	3,938,446.15	
2008 Wind Storm	1,921,076.80	
Rate Case Expenses	1,328,684.60	
EKPC FERC Transmission Cost	780,959.82	
KCCS Funding	633,847.85	
CMRG Funding	179,269.95	
General Management Audit	140,906.06	
Other Deferred Debits	44,953,426.24	44,953,426.24
Total Assets	$ 5,176,733,911.96	$ 5,176,733,911.96

November 21, 2011

Kentucky Utilities Company
Summary Trial Balance
October 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 2,135,768,402.71
Common Stock	308,139,977.56	
Less: Common Stock Expense	321,288.87	
Paid-In Capital	315,858,083.00	
Other Comprehensive Income	(2,464,005.43)	
Retained Earnings	1,498,556,521.70	
Unappropriated Undistributed Subsidiary Earnings	15,999,114.75	
Bonds		1,840,485,686.25
First Mortgage Bonds	1,489,706,281.25	
Pollution Control Bonds - Net of Reacquired Bonds	350,779,405.00	
Accounts Payable		108,573,928.06
Regular	106,896,420.28	
Salaries and Wages Accrued	1,641,851.04	
Employee Withholdings Payable	35,656.74	
Accounts Payable to Associated Companies		27,179,594.19
LG&E - KU Energy Services/Louisville Gas and Electric Company	27,179,594.19	
Customers' Deposits	23,087,841.48	23,087,841.48
Taxes Accrued	27,398,823.34	27,398,823.34
Interest Accrued		30,560,526.52
Mercer County 2000 Series A due 05/01/23 Var%	1,548.00	
Carroll County 2002 Series A due 02/01/32 Var%	6,623.05	
Carroll County 2002 Series B due 02/01/32 Var%	180.82	
Carroll County 2002 Series C due 10/01/32 Var%	23,184.00	
Mercer County 2002 Series A due 02/01/32 Var%	557.53	
Muhlenburg County 2002 Series A due 02/01/32 Var%	180.82	
Carroll County 2004 Series A due 10/01/34 Var%	6,000.01	
Carroll County 2006 Series B due 10/01/34 Var%	6,613.15	
Carroll County 2007 Series A due 02/01/26 5.75%	428,255.21	
Trimble County 2007 Series A due 03/01/37 6.00%	223,175.00	
Carroll County 2008 Series A due 02/01/32 Var%	9,332.33	
First Mortgage Bond due 11/01/15 1.625%	2,031,250.00	
First Mortgage Bond due 11/01/20 3.250%	8,125,000.00	
First Mortgage Bond due 11/01/40 5.125%	19,218,750.00	
Customers' Deposits	448,397.45	
Interest Accrued on Tax Liabilities	16,537.70	
Other	14,941.45	

November 21, 2011

Kentucky Utilities Company
Summary Trial Balance
October 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Miscellaneous Current and Accrued Liabilities		$ 16,277,382.73
Vacation Pay Accrued	6,508,063.88	
Tax Collections Payable	4,024,306.19	
Customer Overpayments	3,034,090.46	
Franchise Fee Payable	2,236,530.17	
Home Energy Assistance	243,651.24	
Derivative Liabilities - Non-Hedging	154,682.48	
Escheated Deposits	(3,488.47)	
Other	79,546.78	
Accumulated Deferred Income Taxes		524,684,542.81
Federal	456,942,763.09	
State	67,741,779.72	
Investment Tax Credit		101,874,450.32
Advanced Coal Credit	99,089,529.00	
Job Development Credit	2,784,921.32	
Regulatory Liabilities		111,397,690.09
Deferred Taxes		
Federal	62,882,403.97	
State	19,824,457.26	
Postretirement Benefits	9,787,090.00	
Environmental Cost Recovery	5,632,375.15	
Asset Retirement Obligations	4,584,239.30	
DSM Cost Recovery	3,903,995.33	
Spare Parts	1,981,952.58	
Fuel Adjustment Clause	1,789,000.00	
MISO Schedule 10 Charges	1,012,176.50	
Customers' Advances for Construction		3,160,049.48
Line Extensions	2,585,999.70	
Other	574,049.78	
Asset Retirement Obligations	59,931,567.75	59,931,567.75
Other Deferred Credits	30,374,354.69	30,374,354.69
Miscellaneous Long-Term Liabilities		2,747,598.99
Workers' Compensation	2,747,598.99	
Accumulated Provision for Benefits		133,231,472.55
Pension Payable	70,301,999.50	
Postretirement Benefits - ASC 715	63,478,562.40	
Post Employment Benefits Payable	5,554,516.00	
Post Employment Medicare Subsidy	(382,793.62)	
Medicare Subsidy - ASC 715	(5,720,811.73)	
Total Liabilities and Stockholders Equity	$ 5,176,733,911.96	$ 5,176,733,911.96

November 21, 2011

Kentucky Utilities Company
Statement of Cash Flows
October 31, 2011

	Year to Date 2011	Year to Date 2010
Cash Flows from Operating Activities		
Net income	$ 148,271,646.88	$ 140,034,814.70
Items not requiring (providing) cash currently:		
Depreciation	151,076,499.81	114,536,854.05
Amortization	5,955,849.97	5,492,351.98
Deferred income taxes - net	82,518,836.58	23,795,290.76
Investment tax credit - net	(2,278,967.00)	-
Gain on disposal of assets	(66,814.11)	(14,154.71)
Other	2,760,163.55	12,575,399.49
Change in receivables	66,578,109.56	19,732,460.42
Change in inventory	(2,278,581.26)	(6,240,980.36)
Change in allowance inventory	94,872.29	370,193.87
Change in payables and accrued expenses	38,594,996.16	25,385,170.59
Change in regulatory assets	(60,290,409.53)	4,983,442.99
Change in regulatory liabilities	56,323,708.81	(1,207,069.17)
Change in other deferred debits	(23,829,834.81)	(1,193,313.01)
Change in other deferred credits	22,232,317.61	(1,102,281.99)
Pension and postretirement funding	(47,364,100.00)	25,663,099.72
Other	(4,427,698.79)	(17,955,700.00)
Less: Allowance for other funds used during construction	(23,790.35)	(1,115,532.72)
Less: Undistributed earnings of subsidiary company	(1,566,719.00)	(3,569,451.00)
Net cash provided (used) by operating activities	432,280,086.37	340,170,595.61
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(202,924,974.41)	(337,605,608.50)
Less: Allowance for other funds used during construction	23,790.35	1,115,532.72
Proceeds received from sale of property	83,020.04	10,503.81
Change in non-hedging derivatives	-	19,719.50
Other	(9,103,189.08)	-
Net cash provided (used) by investing activities	(211,921,353.10)	(336,459,852.47)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(2,808,827.16)	(514.80)
Net change in short-term debt	(10,434,000.00)	48,707,000.00
Dividends on common stock	(87,500,000.00)	(50,000,000.00)
Net cash provided (used) by financing activities	(100,742,827.16)	(1,293,514.80)
Net Increase (Decrease) in Cash and Cash Equivalents	119,615,906.11	2,417,228.34
Cash and Cash Equivalents at Beginning of Period	3,333,446.86	1,672,357.33
Cash and Cash Equivalents at End of Period	$ 122,949,352.97	$ 4,089,585.67

November 21, 2011

Kentucky Utilities Company
Analysis of Interest Charges
October 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Interest on Long-Term Debt						
Loan Agreement - Pollution Control Bonds						
Mercer County 2000 Series A due 05/01/23 Var%..............	$ 1,668.16	$ 3,852.33	$ 21,417.12	$ 34,681.48	$ 28,945.07	$ 44,103.79
Carroll County 2002 Series A due 02/01/32 Var%..............	10,063.60	13,332.12	154,388.87	123,028.29	179,791.58	159,440.75
Carroll County 2002 Series B due 02/01/32 Var%..............	1,121.09	1,528.77	17,284.46	14,107.40	20,197.33	18,282.74
Carroll County 2002 Series C due 10/01/32 Var%..............	26,192.00	46,181.33	232,501.43	603,399.96	316,901.43	644,045.29
Mercer County 2002 Series A due 02/01/32 Var%..............	3,456.71	4,713.70	52,114.25	43,497.83	61,095.61	56,371.80
Muhlenburg County 2002 Series A due 02/01/32 Var%.......	1,121.09	1,528.77	16,901.95	14,107.40	19,814.82	18,282.74
Carroll County 2004 Series A due 10/01/34 Var%..............	6,547.96	12,931.51	91,986.23	124,849.32	117,438.28	151,000.01
Carroll County 2006 Series B due 10/01/34 Var%..............	7,145.75	13,921.64	100,795.06	138,816.99	128,446.02	172,001.10
Carroll County 2007 Series A due 02/01/26 5.75%.............	85,651.04	85,651.03	856,510.42	856,510.42	1,027,812.50	1,027,812.50
Trimble County 2007 Series A due 03/01/37 6.00%............	44,635.00	44,635.00	446,350.00	446,350.00	535,620.00	535,620.00
Carroll County 2008 Series A due 02/01/32 Var%..............	10,101.13	19,753.79	143,850.32	200,741.25	183,336.55	250,499.46
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/01/15 1.625%.........................	338,541.67	-	3,385,416.66	-	3,893,229.17	-
First Mortgage Bond due 11/01/20 3.250%.........................	1,354,166.67	-	13,541,666.66	-	15,572,916.67	-
First Mortgage Bond due 11/01/40 5.125%.........................	3,203,125.00	-	32,031,250.00	-	36,835,937.50	-
Fidelia/PPL..	-	6,098,434.02	-	60,967,046.49	3,048,256.29	73,005,731.22
Total..	5,093,536.87	6,346,464.01	51,092,433.43	63,567,136.83	61,969,738.82	76,083,191.40
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense..................................	290,093.74	18,055.97	2,612,692.06	180,341.96	3,016,474.51	216,358.10
Amortization of Loss on Reacquired Debt...............................	50,414.39	50,414.39	504,143.90	503,988.72	604,972.68	604,754.90
Total..	340,508.13	68,470.36	3,116,835.96	684,330.68	3,621,447.19	821,113.00
Other Interest Charges						
Customers' Deposits..	112,717.05	104,642.30	1,142,610.42	1,153,902.87	1,352,277.42	1,353,515.12
Other Tax Deficiencies..	-	459.00	-	83,145.07	4,496.00	83,145.07
Interest on DSM Cost Recovery...	1,357.46	2,869.86	9,250.00	15,976.31	11,654.38	18,277.20
Interest on Debt to Associated Companies..............................	-	11,269.21	6,083.49	115,542.75	17,584.15	130,041.42
AFUDC Borrowed Funds..	(1,831.33)	(82,598.97)	(10,377.68)	(803,063.93)	(175,910.68)	(990,568.14)
Other Interest Expense..	373,571.49	151,101.67	3,463,824.63	1,723,737.63	4,102,874.93	2,002,601.16
Total..	485,814.67	187,743.07	4,611,390.86	2,289,240.70	5,312,976.20	2,597,011.83
Total Interest...	$ 5,919,859.67	$ 6,602,677.44	$ 58,820,660.25	$ 66,540,708.21	$ 70,904,162.21	$ 79,501,316.23

November 21, 2011

Kentucky Utilities Company
Analysis of Taxes Charged and Accrued
October 31, 2011

Kind of Taxes	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year
Taxes Charged to Accounts 408.1 and 409.1...........				
Property Taxes..	$ 1,549,833.00	$ 908,194.01	$ 15,498,329.77	$ 9,081,940.10
Unemployment..	3,426.19	51,465.60	95,541.33	149,205.37
FICA..	539,909.35	901,290.82	6,082,126.96	6,152,503.92
Public Service Commission Fee..............................	168,112.85	157,659.37	1,618,407.67	1,568,383.26
Federal Income..	5,980,891.91	18,337,562.75	4,450,545.17	48,326,686.20
State Income..	(216,846.15)	5,275,008.54	5,869,169.50	10,152,264.57
Miscellaneous..	13,574.85	13,575.16	68,454.38	73,746.36
Total Charged to Operating Expense..........	8,038,902.00	25,644,756.25	33,682,574.78	75,504,729.78
Taxes Charged to Other Accounts..........................	61,347.88	8,622,149.79	3,145,411.98	14,203,221.18
Taxes Accrued on Intercompany Accounts............	0.00	(247,612.20)	(2,258,172.49)	(2,584,733.05)
Total Taxes Charged.................................	$ 8,100,249.88	$ 34,019,293.84	$ 34,569,814.27	$ 87,123,217.91

Analysis of Taxes Accrued - Account 236

Kind of Taxes	Taxes Accrued At Beginning Of Year	Accruals To Date This Year	Payments To Date This Year	Taxes Accrued At End Of Month
Property Taxes..	$ 8,399,528.00	$ 15,499,999.77	$ 8,882,868.60	$ 15,016,659.17
Unemployment..	75,728.12	59,972.14	135,463.57	236.69
FICA..	639,011.24	5,166,393.73	5,302,503.63	502,901.34
Federal Income..	12,876,014.95	4,070,273.03	5,940,492.00	11,005,795.98
State Income..	2,021,178.48	6,250,701.94	7,759,855.00	512,025.42
Kentucky Sales and Use Tax..................................	581,659.33	3,407,086.88	3,638,975.54	349,770.67
Miscellaneous..	21,662.86	115,386.78	125,615.57	11,434.07
Totals...	$ 24,614,782.98	$ 34,569,814.27	$ 31,785,773.91	$ 27,398,823.34

November 21, 2011

Kentucky Utilities Company
Summary of Utility Plant
October 31, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant in Service**						
Electric						
Electric Distribution................................	$ 1,312,664,325.73	$ 69,217,047.53	$ (15,833,569.61)	$ 787,154.19	$ 54,170,632.11	$ 1,366,834,957.84
Electric General Plant..............................	125,243,994.19	14,156,612.98	(4,169,659.86)	(787,154.19)	9,199,798.93	134,443,793.12
Electric Hydro Production.......................	16,848,655.18	300,776.20	(15,190.72)	-	285,585.48	17,134,240.66
Electric Intangible Plant...........................	49,640,906.77	8,307,621.01	(1,381,084.50)	-	6,926,536.51	56,567,443.28
Electric Other Production........................	519,412,128.33	3,002,985.62	(2,207,165.52)	-	795,820.10	520,207,948.43
Electric Steam Production.......................	1,814,421,935.78	726,862,555.38	(10,477,789.08)	124,492,063.50	840,876,829.80	2,655,298,765.58
Electric Transmission...............................	552,965,733.49	18,285,284.59	(2,383,260.76)	-	15,902,023.83	568,867,757.32
Total 101 Accounts..................................	4,391,197,679.47	840,132,883.31	(36,467,720.05)	124,492,063.50	928,157,226.76	5,319,354,906.23
102 **Electric Plant Purchased or Sold**						
Electric						
Electric Steam...	483,341.17	-	-	-	-	483,341.17
Total 102001	483,341.17	-	-	-	-	483,341.17
105 **Plant Held for Future Use**						
Electric						
Electric Distribution................................	792,599.21	-	-	-	-	792,599.21
Electric Steam...	120,828,152.53	-	-	(120,828,152.53)	(120,828,152.53)	-
Total 105001..	121,620,751.74	-	-	(120,828,152.53)	(120,828,152.53)	792,599.21
106 **Completed Construction Not Classified**						
Electric						
Electric Distribution................................	36,610,963.62	(6,314,080.91)	-	-	(6,314,080.91)	30,296,882.71
Electric General Plant..............................	769,342.30	719,477.53	-	-	719,477.53	1,488,819.83
Electric Hydro Production.......................	-	18,076.75	-	-	18,076.75	18,076.75
Electric Intangible Plant...........................	2,685,464.69	272,951.13	-	-	272,951.13	2,958,415.82
Electric Other Production........................	3,737,695.33	(641,633.86)	-	-	(641,633.86)	3,096,061.47
Electric Steam Production.......................	910,748,505.16	(6,251,818.89)	-	-	(6,251,818.89)	904,496,686.27
Electric Transmission...............................	74,497,274.43	9,800,927.07	-	-	9,800,927.07	84,298,201.50
Total 106 Accounts..................................	1,029,049,245.53	(2,396,101.18)	-	-	(2,396,101.18)	1,026,653,144.35
121 **Nonutility Property**						
Common						
Non Utility Property................................	179,120.94	-	-	-	-	179,120.94
Total 121001	179,120.94	-	-	-	-	179,120.94
107 **Construction Work In Progress**						
Electric						
Electric..	954,430,277.48	(611,721,075.75)	-	-	(611,721,075.75)	342,709,201.73
Total 107001..	954,430,277.48	(611,721,075.75)	-	-	(611,721,075.75)	342,709,201.73
Total Plant (Non-CWIP)................................	5,542,530,138.85	837,736,782.13	(36,467,720.05)	3,663,910.97	804,932,973.05	6,347,463,111.90
Total Plant + CWIP..	6,496,960,416.33	226,015,706.38	(36,467,720.05)	3,663,910.97	193,211,897.30	6,690,172,313.63
Total Plant + CWIP - Nonutility (BS)............	$ 6,496,781,295.39	$ 226,015,706.38	$ (36,467,720.05)	$ 3,663,910.97	$ 193,211,897.30	$ 6,689,993,192.69

November 21, 2011

Kentucky Utilities Company
Summary of Utility Plant - Reserve for Depreciation of Utility Plant
October 31, 2011

	Beginning Balance	Accruals	Retirements	Transfers/ Adjustments	ARO Settlements	RWIP Transfers Out	Cost of Removal	Salvage	Other Credits	Ending Balance
Life Reserve										
Electric Distribution.....................................	$ (398,692,068.83)	$ (23,047,841.49)	$ 15,833,569.61	$ (184,871.61)	$ -	$ -	$ -	$ -	$ -	$ (406,091,212.32)
Electric Distribution - ARO..........................	(790.87)	(3,694.49)	-	-	-	-	-	-	-	(4,485.36)
Electric General Plant..................................	(57,721,732.75)	(5,143,031.29)	4,169,659.86	181,344.61	-	-	-	-	-	(58,513,759.57)
Electric Hydro Production............................	(7,765,077.65)	(99,584.22)	15,190.72	-	-	-	-	-	-	(7,849,471.15)
Electric Hydro Production - ARO................	(121.57)	(810.80)	-	-	-	-	-	-	-	(932.37)
Electric Other Production.............................	(160,412,820.60)	(13,929,432.04)	2,207,165.52	-	-	-	-	-	-	(172,135,087.12)
Electric Other Production - ARO.................	(84.76)	(565.70)	-	-	-	-	-	-	-	(650.46)
Electric Steam Production............................	(1,067,997,942.05)	(74,035,991.43)	10,421,094.16	(282,823.63)	-	-	-	-	-	(1,131,895,662.95)
Electric Steam Production - ARO................	(485,952.30)	(2,506,863.16)	56,694.92	(105,352.11)	-	-	-	-	-	(3,041,472.65)
Electric Transmission...................................	(211,361,531.11)	(7,750,518.90)	2,383,260.76	-	-	-	-	-	-	(216,728,789.25)
Electric Transmission - ARO.......................	(156.99)	(1,046.99)	-	-	-	-	-	-	-	(1,203.98)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(1,904,438,279.48)	(126,519,380.51)	35,086,635.55	(391,702.74)	-	-	-	-	-	(1,996,262,727.18)
Cost of Removal										
Electric Distribution.....................................	(195,818,054.42)	(6,749,859.38)	-	40,000.02	-	-	3,678,778.77	-	-	(198,849,135.01)
Electric General Plant..................................	207,510.70	(37,738.98)	-	(0.02)	-	-	86,267.31	-	-	256,039.01
Electric Hydro Production............................	(374,056.75)	(4,334.25)	-	-	-	-	29,260.00	-	-	(349,131.00)
Electric Other Production.............................	(3,174,464.89)	(746,341.28)	-	-	-	-	69,863.95	-	-	(3,850,942.22)
Electric Steam Production............................	(113,988,699.33)	(20,958,214.77)	-	282,823.63	-	-	2,034,886.24	-	-	(132,629,204.23)
Electric Transmission...................................	(137,175,896.62)	(2,340,679.24)	-	-	-	-	2,384,449.09	-	-	(137,132,126.77)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(450,323,661.31)	(30,837,167.90)	-	322,823.63	-	-	8,283,505.36	-	-	(472,554,500.22)
Salvage										
Electric Distribution.....................................	48,221,606.07	1,646,750.28	-	-	-	-	-	(226,152.32)	-	49,642,204.03
Electric General Plant..................................	149,758.57	-	-	-	-	-	-	(12,678.93)	-	137,079.64
Electric Hydro Production............................	46,518.69	-	-	-	-	-	-	-	-	46,518.69
Electric Other Production.............................	618,891.61	-	-	-	-	-	-	-	-	618,891.61
Electric Steam Production............................	20,938,580.66	3,870,840.09	-	-	-	-	-	(1,360,313.33)	-	23,449,107.42
Electric Transmission...................................	23,009,336.80	543,117.33	-	-	-	-	-	(15,432.54)	-	23,537,021.59
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	92,984,692.40	6,060,707.70	-	-	-	-	-	(1,614,577.12)	-	97,430,822.98
Total Reserves										
Electric Distribution.....................................	(546,288,517.18)	(28,150,950.59)	15,833,569.61	(144,871.59)	-	-	3,678,778.77	(226,152.32)	-	(555,298,143.30)
Electric Distribution - ARO..........................	(790.87)	(3,694.49)	-	-	-	-	-	-	-	(4,485.36)
Electric General Plant..................................	(57,364,463.48)	(5,180,770.27)	4,169,659.86	181,344.59	-	-	86,267.31	(12,678.93)	-	(58,120,640.92)
Electric Hydro Production............................	(8,092,615.71)	(103,918.47)	15,190.72	-	-	-	29,260.00	-	-	(8,152,083.46)
Electric Hydro Production - ARO................	(121.57)	(810.80)	-	-	-	-	-	-	-	(932.37)
Electric Other Production.............................	(162,968,393.88)	(14,675,773.32)	2,207,165.52	-	-	-	69,863.95	-	-	(175,367,137.73)
Electric Other Production - ARO.................	(84.76)	(565.70)	-	-	-	-	-	-	-	(650.46)
Electric Steam Production............................	(1,161,048,060.72)	(91,123,366.11)	10,421,094.16	-	-	-	2,034,886.24	(1,360,313.33)	-	(1,241,075,759.76)
Electric Steam Production - ARO................	(485,952.30)	(2,506,863.16)	56,694.92	(105,352.11)	-	-	-	-	-	(3,041,472.65)
Electric Transmission...................................	(325,528,090.93)	(9,548,080.81)	2,383,260.76	-	-	-	2,384,449.09	(15,432.54)	-	(330,323,894.43)
Electric Transmission - ARO.......................	(156.99)	(1,046.99)	-	-	-	-	-	-	-	(1,203.98)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(2,261,777,248.39)	(151,295,840.71)	35,086,635.55	(68,879.11)	-	-	8,283,505.36	(1,614,577.12)	-	(2,371,386,404.42)
Retirement Work in Process										
Electric...	13,605,672.01		-	14,675.52	(161,732.61)	(6,507,195.63)	10,727,858.64	(753,452.37)	(472,326.54)	16,453,499.02
	13,605,672.01	-	-	14,675.52	(161,732.61)	(6,507,195.63)	10,727,858.64	(753,452.37)	(472,326.54)	16,453,499.02
YTD ACTIVITY	(2,248,171,576.38)	(151,295,840.71)	35,086,635.55	(54,203.59)	(161,732.61)	(6,507,195.63)	19,011,364.00	(2,368,029.49)	(472,326.54)	(2,354,932,905.40)
Amortization										
Electric...	(13,755,205.98)	(5,955,849.97)	1,381,084.50	-	-	-	-	-	-	(18,329,971.45)
	(13,755,205.98)	(5,955,849.97)	1,381,084.50	-	-	-	-	-	-	(18,329,971.45)
Depreciation & Amortization Total										
Depreciation & Amortization Total...............	(2,261,926,782.36)	(157,251,690.68)	36,467,720.05	(54,203.59)	(161,732.61)	(6,507,195.63)	19,011,364.00	(2,368,029.49)	(472,326.54)	(2,373,262,876.85)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)...............	$ 4,234,854,513.03									$ 4,316,730,315.84

November 21, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of October 31, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues..................................	$ 109,334,689.01	$ -	$ 109,334,689.01
Rate Refunds..	-	-	-
Total Operating Revenues....................................	109,334,689.01	-	109,334,689.01
Fuel for Electric Generation.....................................	36,322,228.62	-	36,322,228.62
Power Purchased...	8,143,019.97	-	8,143,019.97
Other Operation Expenses.......................................	18,299,968.94	-	18,299,968.94
Maintenance..	9,234,799.44	-	9,234,799.44
Depreciation..	15,338,724.10	-	15,338,724.10
Amortization Expense...	633,804.87	-	633,804.87
Regulatory Credits...	(506,291.71)	-	(506,291.71)
Taxes			
Federal Income..	5,980,891.91	-	5,980,891.91
State Income..	(216,846.15)	-	(216,846.15)
Deferred Federal Income - Net..............................	(183,443.31)	(22,475.59)	(205,918.90)
Deferred State Income - Net..................................	1,302,323.04	(4,098.89)	1,298,224.15
Property and Other..	2,274,856.24	-	2,274,856.24
Loss (Gain) from Disposition of Allowances...........	-	-	-
Accretion Expense...	250,673.41	-	250,673.41
Total Operating Expenses.....................................	96,874,709.37	(26,574.48)	96,848,134.89
Net Operating Income...	12,459,979.64	26,574.48	12,486,554.12
Other Income Less Deductions			
Amortization of Investment Tax Credit.............	233,343.00	-	233,343.00
Other Income Less Deductions..........................	(377,414.24)	(73,840.35)	(451,254.59)
AFUDC - Equity...	6,036.17	-	6,036.17
Total Other Income Less Deductions....................	(138,035.07)	(73,840.35)	(211,875.42)
Income Before Interest Charges............................	12,321,944.57	(47,265.87)	12,274,678.70
Interest on Long-Term Debt....................................	5,093,536.87	(5,525.49)	5,088,011.38
Amortization of Debt Expense - Net........................	340,508.13	-	340,508.13
Other Interest Expenses...	487,646.00	-	487,646.00
AFUDC - Borrowed Funds......................................	(1,831.33)	-	(1,831.33)
Total Interest Charges...	5,919,859.67	(5,525.49)	5,914,334.18
Net Income..	$ 6,402,084.90	$ (41,740.38)	$ 6,360,344.52

Note: Purchase accounting is subject to change through October 31, 2011

November 21, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of October 31, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 1,300,011,645.49	$ -	$ 1,300,011,645.49
Rate Refunds	-	-	-
Total Operating Revenues	1,300,011,645.49	-	1,300,011,645.49
Fuel for Electric Generation	442,149,279.31	-	442,149,279.31
Power Purchased	91,111,399.79	-	91,111,399.79
Other Operation Expenses	194,406,093.28	31,612.30	194,437,705.58
Maintenance	98,689,496.44	-	98,689,496.44
Depreciation	151,076,499.81	-	151,076,499.81
Amortization Expense	5,955,849.97	-	5,955,849.97
Regulatory Credits	(4,835,540.16)	-	(4,835,540.16)
Taxes			
Federal Income	4,450,545.17	-	4,450,545.17
State Income	5,869,169.50	-	5,869,169.50
Deferred Federal Income - Net	75,320,584.34	(16,458.03)	75,304,126.31
Deferred State Income - Net	6,441,563.05	(3,001.47)	6,438,561.58
Property and Other	23,362,860.11	-	23,362,860.11
Loss (Gain) from Disposition of Allowances	(3,293.39)	-	(3,293.39)
Accretion Expense	2,322,559.02	-	2,322,559.02
Total Operating Expenses	1,096,317,066.24	12,152.80	1,096,329,219.04
Net Operating Income	203,694,579.25	(12,152.80)	203,682,426.45
Other Income Less Deductions			
Amortization of Investment Tax Credit	2,219,719.00	-	2,219,719.00
Other Income Less Deductions	1,143,840.85	787,591.44	1,931,432.29
AFUDC - Equity	34,168.03	-	34,168.03
Total Other Income Less Deductions	3,397,727.88	787,591.44	4,185,319.32
Income Before Interest Charges	207,092,307.13	775,438.64	207,867,745.77
Interest on Long-Term Debt	51,092,433.43	(55,254.91)	51,037,178.52
Amortization of Debt Expense - Net	3,116,835.96	-	3,116,835.96
Other Interest Expenses	4,621,768.54	-	4,621,768.54
AFUDC - Borrowed Funds	(10,377.68)	-	(10,377.68)
Total Interest Charges	58,820,660.25	(55,254.91)	58,765,405.34
Net Income	$ 148,271,646.88	$ 830,693.55	$ 149,102,340.43

Note: Purchase accounting is subject to change through October 31, 2011

November 21, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of October 31, 2011

Retained Earnings and Undistributed Earnings	Current Month without Purchase Accounting: Retained Earnings	Current Month without Purchase Accounting: Undistributed Subsidiary Earnings	Current Month Purchase Accounting: Retained Earnings	Current Month Purchase Accounting: Undistributed Subsidiary Earnings	Current Month Combined: Retained Earnings	Current Month Combined: Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,491,575,229.80	$ 16,578,321.75	$ (1,402,463,054.70)	$ (15,053,063.59)	$ 89,112,175.10	$ 1,525,258.16
Add						
Net Income for Period..	6,402,084.90	-	(41,740.38)	-	6,360,344.52	-
Deductions:						
Common Dividends						
Common Stock Without Par Value..................	-	-	-	-	-	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc...	579,207.00	(579,207.00)	73,840.35	(73,840.35)	653,047.35	(653,047.35)
Balance at End of Period	$ 1,498,556,521.70	$ 15,999,114.75	$ (1,402,430,954.73)	$ (15,126,903.94)	$ 96,125,566.97	$ 872,210.81
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings................		15,999,114.75		(15,126,903.94)		872,210.81
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.........................		$ 6,223,655.64		$ (5,884,365.63)		$ 339,290.01

Note: Purchase accounting is subject to change through October 31, 2011.

November 21, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of October 31, 2011

Retained Earnings and Undistributed Earnings	Year to Date without Purchase Accounting: Retained Earnings	Year to Date without Purchase Accounting: Undistributed Subsidiary Earnings	Year to Date Purchase Accounting: Retained Earnings	Year to Date Purchase Accounting: Undistributed Subsidiary Earnings	Year to Date Combined: Retained Earnings	Year to Date Combined: Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,439,351,593.82	$ 14,432,395.75	$ (1,404,000,051.78)	$ (14,388,500.44)	$ 35,351,542.04	$ 43,895.31
Add						
Net Income for Period ………………………………	148,271,646.88	-	830,693.55	-	149,102,340.43	-
Deductions:						
Common Dividends						
Common Stock Without Par Value....................	(87,500,000.00)	-	-	-	(87,500,000.00)	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc……………………….…………	(1,566,719.00)	1,566,719.00	738,403.50	(738,403.50)	(828,315.50)	828,315.50
Balance at End of Period …...……………………………	$ 1,498,556,521.70	$ 15,999,114.75	$ (1,402,430,954.73)	$ (15,126,903.94)	$ 96,125,566.97	$ 872,210.81
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings…………		15,999,114.75		(15,126,903.94)		872,210.81
Statutory Tax Rate…...…………………………………		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary…...………………		$ 6,223,655.64		$ (5,884,365.63)		$ 339,290.01

Note: Purchase accounting is subject to change through October 31, 2011

November 21, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of October 31, 2011

Retained Earnings and Undistributed Earnings	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,404,083,566.85	$ 14,240,819.75	$ -	$ -	$ 1,404,083,566.85	$ 14,240,819.75
Add						
Net Income for Period...	183,731,249.85	-	766,527.93	-	184,497,777.78	-
Purchase Accounting Deductions:	-	-	(1,404,083,566.85)	(14,240,819.75)	(1,404,083,566.85)	(14,240,819.75)
Deductions:						
Common Dividends						
Common Stock Without Par Value...................	(87,500,000.00)	-	-	-	(87,500,000.00)	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	(1,758,295.00)	1,758,295.00	886,084.19	(886,084.19)	(872,210.81)	872,210.81
Balance at End of Period	$ 1,498,556,521.70	$ 15,999,114.75	$ (1,402,430,954.73)	$ (15,126,903.94)	$ 96,125,566.97	$ 872,210.81

Deferred Taxes Related to Undistributed Subsidiary Earnings	Year Ended Current Month without Purchase Accounting	Year Ended Current Month to Date Purchase Accounting	Year Ended Current Month Combined
Balance of Undistributed Subsidiary Earnings................	15,999,114.75	(15,126,903.94)	872,210.81
Statutory Tax Rate..	38.9%	38.9%	38.9%
Deferred Taxes on Equity in Subsidiary..........................	$ 6,223,655.64	$ (5,884,365.63)	$ 339,290.01

Combined Balance of Retained Earnings	12 MONTHS 10/31/2011	12 MONTHS 10/31/2010
Retained Earnings at Beginning of Period........................	$ 1,418,324,386.60	$ 1,309,451,735.83
Net Income for Period	184,497,777.78	156,303,495.36
FIN 48 Adjustment...	-	-
Subtotal..	1,602,822,164.38	1,465,755,231.19
Deduct		
Purchase Accounting Adjustment................................	1,418,324,386.60	-
Dividends on Common Stock.....................................	87,500,000.00	50,000,000.00
Retained Earnings at End of Period.................................	$ 96,997,777.78	$ 1,415,755,231.19

Note: Purchase accounting is subject to change through October 31, 2011

November 21, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of October 31, 2011

Assets	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 6,689,993,192.69	$ -	$ 6,689,993,192.69
Less Reserves for Depreciation and Amortization.....	2,373,262,876.85	-	2,373,262,876.85
Total..	4,316,730,315.84	-	4,316,730,315.84
Investments			
Electric Energy, Inc...	13,257,506.55	16,835,598.81	30,093,105.36
Ohio Valley Electric Corporation.............................	250,000.00	-	250,000.00
Nonutility Property - Less Reserve...........................	179,120.94	-	179,120.94
Special Funds...	-	-	-
Total..	13,686,627.49	16,835,598.81	30,522,226.30
Current and Accrued Assets			
Cash..	38,368,881.00	-	38,368,881.00
Special Deposits..	91,580.74	-	91,580.74
Temporary Cash Investments.................................	84,580,471.97	-	84,580,471.97
Accounts Receivable-Less Reserve........................	141,041,770.72	-	141,041,770.72
Accounts Receivable from Assoc Companies..........	455,305.37	-	455,305.37
Materials & Supplies-At Average Cost			
Fuel...	95,361,449.01	-	95,361,449.01
Plant Materials & Operating Supplies..................	33,838,235.20	-	33,838,235.20
Stores Expense..	9,915,258.19	-	9,915,258.19
Allowance Inventory..	471,706.71	-	471,706.71
Prepayments..	7,404,467.92	-	7,404,467.92
Miscellaneous Current & Accrued Assets..............	99,869.06	-	99,869.06
Total..	411,628,995.89	-	411,628,995.89
Deferred Debits and Other			
Unamortized Debt Expense......................................	21,939,036.47	(4,445,864.37)	17,493,172.10
Unamortized Loss on Bonds....................................	11,875,946.15	-	11,875,946.15
Accumulated Deferred Income Taxes.......................	80,128,837.66	63,325,811.92	143,454,649.58
Deferred Regulatory Assets.....................................	275,790,726.22	13,254,580.53	289,045,306.75
Other Deferred Debits..	44,953,426.24	147,867,142.16	192,820,568.40
Goodwill...	-	607,404,368.23	607,404,368.23
Total..	434,687,972.74	827,406,038.47	1,262,094,011.21
Total Assets..	$ 5,176,733,911.96	$ 844,241,637.28	$ 6,020,975,549.24

Note: Purchase accounting is subject to change through October 31, 2011

November 21, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of October 31, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Proprietary Capital			
Common Stock..	$ 308,139,977.56	$ -	$ 308,139,977.56
Less: Common Stock Expense....................................	321,288.87	-	321,288.87
Paid-In Capital..	315,858,083.00	2,032,588,750.94	2,348,446,833.94
Other Comprehensive Income.....................................	(2,464,005.43)	1,990,823.26	(473,182.17)
Retained Earnings..	1,498,556,521.70	(1,402,430,954.73)	96,125,566.97
Unappropriated Undistributed Subsidiary Earnings....	15,999,114.75	(15,126,903.94)	872,210.81
Total Proprietary Capital..	2,135,768,402.71	617,021,715.53	2,752,790,118.24
Pollution Control Bonds - Net of Reacquired Bonds...	350,779,405.00	1,095,149.11	351,874,554.11
First Mortgage Bonds..	1,489,706,281.25	-	1,489,706,281.25
Total Long-Term Debt...	1,840,485,686.25	1,095,149.11	1,841,580,835.36
Total Capitalization..	3,976,254,088.96	618,116,864.64	4,594,370,953.60
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Accounts Payable...	108,573,928.06	-	108,573,928.06
Accounts Payable to Associated Companies................	27,179,594.19	-	27,179,594.19
Customer Deposits...	23,087,841.48	-	23,087,841.48
Taxes Accrued..	27,398,823.34	-	27,398,823.34
Interest Accrued...	30,560,526.52	-	30,560,526.52
Dividends Declared..	-	-	-
Miscellaneous Current and Accrued Liabilities...........	16,277,382.73	-	16,277,382.73
Total..	233,078,096.32	-	233,078,096.32
Deferred Credits and Other			
Accumulated Deferred Income Taxes..........................	524,684,542.81	69,448,914.32	594,133,457.13
Investment Tax Credit..	101,874,450.32	-	101,874,450.32
Regulatory Liabilities...	111,397,690.09	147,867,142.16	259,264,832.25
Customer Advances for Construction..........................	3,160,049.48	-	3,160,049.48
Asset Retirement Obligations......................................	59,931,567.75	-	59,931,567.75
Other Deferred Credits...	30,374,354.69	8,808,716.16	39,183,070.85
Miscellaneous Long-Term Liabilities...........................	2,747,598.99	-	2,747,598.99
Accum Provision for Postretirement Benefits.............	133,231,472.55	-	133,231,472.55
Total..	967,401,726.68	226,124,772.64	1,193,526,499.32
Total Liabilities and Stockholders' Equity.........................	$ 5,176,733,911.96	$ 844,241,637.28	$ 6,020,975,549.24

Note: Purchase accounting is subject to change through October 31, 2011

November 21, 2011

KENTUCKY UTILITIES COMPANY

Financial Reports

September 30, 2011

Index
Financial and Operating Reports

Kentucky Utilities Company
September 30, 2011

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2011 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows, unless otherwise noted.

Kentucky Utilities Company
Comparative Statement of Income
September 30, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 118,228,868.75	$ 122,202,198.88	$ (3,973,330.13)	(3.25)
Rate Refunds	-	-	-	-
Total Operating Revenues	118,228,868.75	122,202,198.88	(3,973,330.13)	(3.25)
Fuel for Electric Generation	37,189,335.90	39,292,519.43	(2,103,183.53)	(5.35)
Power Purchased	10,277,734.39	14,837,867.61	(4,560,133.22)	(30.73)
Other Operation Expenses	19,991,779.38	19,288,582.26	703,197.12	3.65
Maintenance	8,219,602.96	8,365,496.53	(145,893.57)	(1.74)
Depreciation	15,311,906.86	12,949,310.30	2,362,596.56	18.25
Amortization Expense	610,010.22	544,521.28	65,488.94	12.03
Regulatory Credits	(499,374.55)	(2,328,117.85)	1,828,743.30	78.55
Taxes				
Federal Income	(20,832,844.80)	(5,580,322.91)	(15,252,521.89)	(273.33)
State Income	(2,523,082.85)	(646,498.83)	(1,876,584.02)	(290.27)
Deferred Federal Income - Net	26,823,528.87	10,255,369.81	16,568,159.06	161.56
Deferred State Income - Net	2,446,447.81	2,112,655.71	333,792.10	15.80
Property and Other	2,710,224.88	1,639,239.05	1,070,985.83	65.33
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	-	-	-	-
Accretion Expense	249,609.23	1,420,180.67	(1,170,571.44)	(82.42)
Total Operating Expenses	99,974,878.30	102,150,803.06	(2,175,924.76)	(2.13)
Net Operating Income	18,253,990.45	20,051,395.82	(1,797,405.37)	(8.96)
Other Income Less Deductions				
Amortization of Investment Tax Credit	233,343.00	5,925.00	227,418.00	3,838.28
Other Income Less Deductions	169,822.96	(137,559.50)	307,382.46	223.45
AFUDC - Equity	5,358.25	104,159.75	(98,801.50)	(94.86)
Total Other Income Less Deductions	408,524.21	(27,474.75)	435,998.96	1,586.91
Income Before Interest Charges	18,662,514.66	20,023,921.07	(1,361,406.41)	(6.80)
Interest on Long-Term Debt	5,094,446.85	6,342,552.55	(1,248,105.70)	(19.68)
Amortization of Debt Expense - Net	325,108.13	68,470.36	256,637.77	374.82
Other Interest Expenses	376,010.30	507,555.33	(131,545.03)	(25.92)
AFUDC - Borrowed Funds	(1,625.79)	(82,605.42)	80,979.63	98.03
Total Interest Charges	5,793,939.49	6,835,972.82	(1,042,033.33)	(15.24)
Net Income	$ 12,868,575.17	$ 13,187,948.25	$ (319,373.08)	(2.42)

October 26, 2011

Kentucky Utilities Company
Comparative Statement of Income
September 30, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues.....................................	$ 1,190,676,956.48	$ 1,146,853,960.94	$ 43,822,995.54	3.82
Rate Refunds..	-	(632,390.04)	632,390.04	100.00
Total Operating Revenues......................................	1,190,676,956.48	1,146,221,570.90	44,455,385.58	3.88
Fuel for Electric Generation......................................	405,827,050.69	391,144,687.19	14,682,363.50	3.75
Power Purchased...	82,968,379.82	134,624,406.33	(51,656,026.51)	(38.37)
Other Operation Expenses..	176,106,124.34	163,444,662.26	12,661,462.08	7.75
Maintenance..	89,454,697.00	72,734,162.93	16,720,534.07	22.99
Depreciation..	135,737,775.71	102,428,064.21	33,309,711.50	32.52
Amortization Expense...	5,322,045.10	4,943,299.63	378,745.47	7.66
Regulatory Credits..	(4,329,248.45)	(3,996,346.09)	(332,902.36)	(8.33)
Taxes				
Federal Income...	(1,530,346.74)	29,989,123.45	(31,519,470.19)	(105.10)
State Income...	6,086,015.65	4,877,256.03	1,208,759.62	24.78
Deferred Federal Income - Net...............................	75,504,027.65	33,754,646.17	41,749,381.48	123.68
Deferred State Income - Net...................................	5,139,240.01	7,209,485.95	(2,070,245.94)	(28.72)
Property and Other...	21,088,003.87	14,993,594.05	6,094,409.82	40.65
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances...........	(3,293.39)	(44,023.81)	40,730.42	92.52
Accretion Expense..	2,071,885.61	2,890,335.60	(818,449.99)	(28.32)
Total Operating Expenses......................................	999,442,356.87	958,993,353.90	40,449,002.97	4.22
Net Operating Income...	191,234,599.61	187,228,217.00	4,006,382.61	2.14
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	1,986,376.00	53,325.00	1,933,051.00	3,625.04
Other Income Less Deductions...........................	1,521,255.09	1,466,369.82	54,885.27	3.74
AFUDC - Equity...	28,131.86	208,084.76	(179,952.90)	(86.48)
Total Other Income Less Deductions.....................	3,535,762.95	1,727,779.58	1,807,983.37	104.64
Income Before Interest Charges.............................	194,770,362.56	188,955,996.58	5,814,365.98	3.08
Interest on Long-Term Debt......................................	45,998,896.56	57,220,672.82	(11,221,776.26)	(19.61)
Amortization of Debt Expense - Net.........................	2,776,327.83	615,860.32	2,160,467.51	350.80
Other Interest Expenses..	4,134,122.54	2,821,962.59	1,312,159.95	46.50
AFUDC - Borrowed Funds.......................................	(8,546.35)	(720,464.96)	711,918.61	98.81
Total Interest Charges..	52,900,800.58	59,938,030.77	(7,037,230.19)	(11.74)
Net Income..	$ 141,869,561.98	$ 129,017,965.81	$ 12,851,596.17	9.96

October 26, 2011

Kentucky Utilities Company
Comparative Statement of Income
September 30, 2011

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 1,556,165,091.46	$ 1,490,068,006.42	$ 66,097,085.04	4.44
Rate Refunds	6.12	(1,101,620.83)	1,101,626.95	100.00
Total Operating Revenues	1,556,165,097.58	1,488,966,385.59	67,198,711.99	4.51
Fuel for Electric Generation	510,766,551.63	496,097,789.57	14,668,762.06	2.96
Power Purchased	122,965,910.76	179,712,815.53	(56,746,904.77)	(31.58)
Other Operation Expenses	229,308,689.85	214,905,065.99	14,403,623.86	6.70
Maintenance	124,534,518.87	104,816,859.26	19,717,659.61	18.81
Depreciation	172,591,752.19	134,645,650.74	37,946,101.45	28.18
Amortization Expense	6,982,209.39	6,605,552.12	376,657.27	5.70
Regulatory Credits	(5,482,459.71)	(4,606,354.23)	(876,105.48)	(19.02)
Taxes				
Federal Income	30,139,979.09	41,275,932.86	(11,135,953.77)	(26.98)
State Income	13,965,152.13	5,831,010.22	8,134,141.91	139.50
Deferred Federal Income - Net	64,024,833.23	32,687,661.75	31,337,171.48	95.87
Deferred State Income - Net	1,240,792.24	8,478,724.68	(7,237,932.44)	(85.37)
Property and Other	25,987,888.79	18,150,457.05	7,837,431.74	43.18
Investment Tax Credit	-	4,437,887.54	(4,437,887.54)	(100.00)
Loss (Gain) from Disposition of Allowances	(16,020.32)	(44,023.81)	28,003.49	63.61
Accretion Expense	2,680,454.95	3,426,108.44	(745,653.49)	(21.76)
Total Operating Expenses	1,299,690,253.09	1,246,421,137.71	53,269,115.38	4.27
Net Operating Income	256,474,844.49	242,545,247.88	13,929,596.61	5.74
Other Income Less Deductions				
Amortization of Investment Tax Credit	2,004,151.00	95,555.75	1,908,595.25	1,997.36
Other Income Less Deductions	1,112,799.19	(677,385.23)	1,790,184.42	264.28
AFUDC - Equity	341,199.14	863,723.53	(522,524.39)	(60.50)
Total Other Income Less Deductions	3,458,149.33	281,894.05	3,176,255.28	1,126.76
Income Before Interest Charges	259,932,993.82	242,827,141.93	17,105,851.89	7.04
Interest on Long-Term Debt	63,222,665.96	75,891,263.09	(12,668,597.13)	(16.69)
Amortization of Debt Expense - Net	3,349,409.42	821,029.00	2,528,380.42	307.95
Other Interest Expenses	5,271,582.92	3,564,814.84	1,706,768.08	47.88
AFUDC - Borrowed Funds	(256,678.32)	(999,736.54)	743,058.22	74.33
Total Interest Charges	71,586,979.98	79,277,370.39	(7,690,390.41)	(9.70)
Net Income	$ 188,346,013.84	$ 163,549,771.54	$ 24,796,242.30	15.16

October 26, 2011

Kentucky Utilities Company
Analysis of Retained Earnings
September 30, 2011

	Current Month		Year to Date		Year Ended Current Month	
Retained Earnings and Undistributed Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period..	$ 1,478,582,672.63	$ 16,702,303.75	$ 1,439,351,593.82	$ 14,432,395.75	$ 1,392,973,602.96	$ 14,333,934.75
Add:						
Net Income for Period...	12,868,575.17	-	141,869,561.98	-	188,346,013.84	-
Deduct:						
Common Dividends						
Common Stock Without Par Value	-	-	(87,500,000.00)	-	(87,500,000.00)	-
EE Inc...	123,982.00	(123,982.00)	(2,145,926.00)	2,145,926.00	(2,244,387.00)	2,244,387.00
Balance at End of Period..	$ 1,491,575,229.80	$ 16,578,321.75	$ 1,491,575,229.80	$ 16,578,321.75	$ 1,491,575,229.80	$ 16,578,321.75
Deferred Taxes Related to Undistributed Subsidiary Earnings		-		-		-
Balance of Undistributed Subsidiary Earnings.............................		16,578,321.75		16,578,321.75		16,578,321.75
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.......................................		$ 6,448,967.16		$ 6,448,967.16		$ 6,448,967.16

October 26, 2011

Kentucky Utilities Company
Comparative Balance Sheets as of September 30, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,643,168,375.96	$ 6,371,464,914.51
Less: Reserves for Depreciation and Amortization	2,358,394,526.17	2,244,953,370.57
Total	4,284,773,849.79	4,126,511,543.94
Investments		
Electric Energy, Inc	13,829,384.55	12,373,766.55
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	179,120.94	179,120.94
Total	14,258,505.49	12,802,887.49
Current and Accrued Assets		
Cash	33,388,033.43	2,294,104.35
Special Deposits	91,321.13	-
Temporary Cash Investments	60,622,322.35	269.25
Accounts Receivable-Less Reserve	159,643,815.32	203,524,624.07
Accounts Receivable from Associated Companies	1,609,818.79	101,637.85
Materials and Supplies-At Average Cost		
Fuel	79,497,725.17	97,727,334.48
Plant Materials and Operating Supplies	33,017,684.80	32,805,788.34
Stores Expense	9,979,032.00	8,539,663.75
Emission Allowances	481,830.29	563,902.79
Prepayments	8,400,992.34	5,362,645.86
Miscellaneous Current and Accrued Assets	137,330.72	52,406.69
Total	386,869,906.34	350,972,377.43
Deferred Debits and Other		
Unamortized Debt Expense	21,504,432.75	4,680,591.98
Unamortized Loss on Bonds	11,926,360.54	12,531,333.22
Accumulated Deferred Income Taxes	79,869,550.38	51,412,681.67
Deferred Regulatory Assets	280,492,761.03	228,918,075.74
Other Deferred Debits	44,618,845.07	41,209,403.38
Total	438,411,949.77	338,752,085.99
Total Assets	$ 5,124,314,211.39	$ 4,829,038,894.85

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	315,858,083.00	315,858,083.00
Other Comprehensive Income	(2,471,334.43)	(1,989,396.57)
Retained Earnings	1,491,575,229.80	1,392,973,602.96
Unappropriated Undistributed Subsidiary Earnings	16,578,321.75	14,333,934.75
Total Proprietary Capital	2,129,358,988.81	2,028,994,912.83
Pollution Control Bonds	350,779,405.00	350,779,405.00
First Mortgage Bonds	1,489,653,343.75	-
LT Notes Payable to Associated Companies	-	1,298,000,000.00
Total Long-Term Debt	1,840,432,748.75	1,648,779,405.00
Total Capitalization	3,969,791,737.56	3,677,774,317.83
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	94,183,954.00
Accounts Payable	76,040,751.20	108,985,615.29
Accounts Payable to Associated Companies	24,405,061.94	71,260,641.15
Customer Deposits	23,179,523.85	22,549,174.93
Taxes Accrued	20,297,158.25	8,503,717.04
Interest Accrued	25,441,185.16	1,011,641.50
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	20,585,681.94	20,377,415.78
Total	189,949,362.34	326,872,159.69
Deferred Credits and Other		
Accumulated Deferred Income Taxes	523,972,924.09	425,743,298.85
Investment Tax Credit	102,107,793.32	104,111,944.32
Regulatory Liabilities	110,573,506.55	49,306,438.45
Customer Advances for Construction	3,183,439.02	3,102,966.47
Asset Retirement Obligations	59,680,894.34	59,347,356.75
Other Deferred Credits	27,990,982.63	30,303,293.46
Miscellaneous Long-Term Liabilities	2,747,598.99	3,047,147.96
Accum Provision for Postretirement Benefits	134,315,972.55	149,429,971.07
Total	964,573,111.49	824,392,417.33
Total Liabilities and Stockholders Equity	$ 5,124,314,211.39	$ 4,829,038,894.85

October 26, 2011

Kentucky Utilities Company
Statement of Capitalization and Short-Term Debt
September 30, 2011

	Authorized Shares	Issued and Outstanding Shares	Issued and Outstanding Amount	Percent of Total Capital
Proprietary Capital				
Common Stock - Without Par...	80,000,000	37,817,878	$ 308,139,977.56	
Less: Common Stock Expense..			321,288.87	
Paid-In Capital..			315,858,083.00	
Other Comprehensive Income...			(2,471,334.43)	
Retained Earnings...			1,491,575,229.80	
Unappropriated Undistributed Subsidiary Earnings.............			16,578,321.75	
Total Proprietary Capital..			2,129,358,988.81	53.64
Long-Term Debt				
Pollution Control Bonds				
Mercer County 2000 Series A due 05/01/23 Var%..........			12,900,000.00	
Carroll County 2002 Series A due 02/01/32 Var%..........			20,930,000.00	
Carroll County 2002 Series B due 02/01/32 Var%..........			2,400,000.00	
Carroll County 2002 Series C due 10/01/32 Var%..........			96,000,000.00	
Mercer County 2002 Series A due 02/01/32 Var%..........			7,400,000.00	
Muhlenburg County 2002 Series A due 02/01/32 Var%...			2,400,000.00	
Carroll County 2004 Series A due 10/01/34 Var%..........			50,000,000.00	
Carroll County 2006 Series B due 10/01/34 Var%..........			54,000,000.00	
Carroll County 2007 Series A due 02/01/26 5.75%.........			17,875,000.00	
Trimble County 2007 Series A due 03/01/37 6.00%.........			8,927,000.00	
Carroll County 2008 Series A due 02/01/32 Var%..........			77,947,405.00	
Total Pollution Control Bonds..			350,779,405.00	8.84
First Mortgage Bonds				
First Mortgage Bond due 11/01/15 1.625%.......................			250,000,000.00	
First Mortgage Bond due 11/01/20 3.250%......................			500,000,000.00	
First Mortgage Bond due 11/01/40 5.125%......................			750,000,000.00	
Total First Mortgage Bonds..			1,500,000,000.00	37.78
Less: First Mortgage Bonds Debt Discount				
First Mortgage Bond due 11/01/15 1.625%.......................			(721,875.01)	
First Mortgage Bond due 11/01/20 3.250%......................			(1,724,625.00)	
First Mortgage Bond due 11/01/40 5.125%......................			(7,900,156.24)	
			(10,346,656.25)	(0.26)
Total First Mortgage Bonds - Net of Debt Discount............			1,489,653,343.75	37.52
Total Capitalization...			$ 3,969,791,737.56	100.00

October 26, 2011

Kentucky Utilities Company
Summary Trial Balance
September 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 6,643,168,375.96	$ 6,643,168,375.96
Reserves for Depreciation and Amortization		(2,358,394,526.17)
Depreciation of Plant	(2,340,698,359.59)	
Amortization of Plant	(17,696,166.58)	
Investments		14,258,505.49
Electric Energy, Inc	13,829,384.55	
Ohio Valley Electric Corporation	250,000.00	
Nonutility Property Reserve	179,120.94	
Cash	33,388,033.43	33,388,033.43
Special Deposits		91,321.13
MAN Margin Call	91,321.13	
Temporary Cash Investments	60,622,322.35	60,622,322.35
Accounts Receivable - Less Reserve		159,643,815.32
Customers - Active	82,128,925.80	
Unbilled Revenues	69,874,643.10	
IMPA	1,533,198.06	
IMEA	1,442,352.82	
Transmission Sales	1,274,814.74	
Mutual Aid	1,085,535.17	
Damage Claims	329,945.06	
Bechtel Liquidated Damages	24,300.00	
Sundry Accounts Receivable	5,078.16	
Other	4,457,572.38	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	6,807,899.30	
Accrual	(4,877,278.62)	
Reserve	(2,227,775.00)	
Recoveries	(1,930,486.49)	
A/R Miscellaneous	(284,909.16)	
Accounts Receivable from Associated Companies		1,609,818.79
LG&E - KU Energy Services/Louisville Gas and Electric Company	1,375,675.45	
PPL Energy Funding	234,143.34	
Fuel		79,497,725.17
Coal 1,382,909.89 Tons @ $52.37 MMBtu 31,653,930.81 @ 228.78¢	72,417,415.68	
Fuel Oil 2,820,369 Gallons @ 248.89¢	7,019,489.44	
Gas Pipeline 12,269.90 Mcf @ $4.96	60,820.05	
Plant Materials and Operating Supplies		33,017,684.80
Regular Materials and Supplies	32,404,955.59	
Limestone 57,886.20 Tons @ $10.59	612,729.18	
Other Reagents	0.03	
Stores Expense Undistributed	9,979,032.00	9,979,032.00

October 26, 2011

Kentucky Utilities Company
Summary Trial Balance
September 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Emission Allowances	$ 481,830.29	$ 481,830.29
Prepayments		8,400,992.34
Insurance	2,889,156.16	
Taxes	1,513,015.71	
Lease	632,753.26	
Risk Management and Workers Compensation	75,000.00	
Other	3,291,067.21	
Miscellaneous Current Assets		137,330.72
Derivative Asset - Non-Hedging	137,330.72	
Unamortized Debt Expense		21,504,432.75
Carroll County 2002 Series A due 02/01/32 Var%	83,370.34	
Carroll County 2002 Series B due 02/01/32 Var%	57,943.62	
Carroll County 2002 Series C due 10/01/32 Var%	1,546,817.85	
Mercer County 2002 Series A due 02/01/32 Var%	23,273.40	
Muhlenburg County 2002 Series A due 02/01/32 Var%	64,502.11	
Carroll County 2006 Series B due 10/01/34 Var%	1,102,160.76	
Carroll County 2007 Series A due 02/01/26 5.75%	477,903.78	
Trimble County 2007 Series A due 03/01/37 6.00%	408,488.47	
Carroll County 2008 Series A due 02/01/32 Var%	699,460.01	
First Mortgage Bond due 11/01/15 1.625%	1,886,976.29	
First Mortgage Bond due 11/01/20 3.250%	3,804,844.58	
First Mortgage Bond due 11/01/40 5.125%	7,260,468.27	
Revolving Credit Agreement	4,088,223.27	
Unamortized Loss on Bonds		11,926,360.54
Refinanced and Called Bonds	11,926,360.54	
Accumulated Deferred Income Taxes		79,869,550.38
Federal	67,649,267.40	
State	12,220,282.98	
Regulatory Assets		280,492,761.03
Pension and Postretirement Benefits	117,274,368.11	
ASC 740 - Deferred Taxes	76,771,478.57	
2009 Winter Storm	50,559,136.70	
Virginia Mountain Snowstorm	6,041,670.12	
Asset Retirement Obligations	5,949,240.61	
FERC Jurisdictional Pension Expense	5,621,868.74	
VA Fuel Component Non-Current	4,537,000.00	
Fuel Adjustment Clause	4,531,000.00	
MISO Exit Fee	4,053,981.40	
2008 Wind Storm	1,939,372.77	
Rate Case Expenses	1,423,024.73	
EKPC FERC Transmission Cost	808,851.24	
KCCS Funding	653,055.36	
CMRG Funding	187,806.62	
General Management Audit	140,906.06	
Other Deferred Debits	44,618,845.07	44,618,845.07
Total Assets	$ 5,124,314,211.39	$ 5,124,314,211.39

October 26, 2011

Kentucky Utilities Company
Summary Trial Balance
September 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 2,129,358,988.81
Common Stock	308,139,977.56	
Less: Common Stock Expense	321,288.87	
Paid-In Capital	315,858,083.00	
Other Comprehensive Income	(2,471,334.43)	
Retained Earnings	1,491,575,229.80	
Unappropriated Undistributed Subsidiary Earnings	16,578,321.75	
Bonds		1,840,432,748.75
Pollution Control Bonds - Net of Reacquired Bonds	350,779,405.00	
First Mortgage Bonds	1,489,653,343.75	
Accounts Payable		76,040,751.20
Regular	74,520,714.43	
Salaries and Wages Accrued	1,473,709.89	
Employee Withholdings Payable	46,326.88	
Accounts Payable to Associated Companies		24,405,061.94
LG&E - KU Energy Services/Louisville Gas and Electric Company	24,405,061.94	
Customers' Deposits	23,179,523.85	23,179,523.85
Taxes Accrued	20,297,158.25	20,297,158.25
Interest Accrued		25,441,185.16
Mercer County 2000 Series A due 05/01/23 Var%	1,770.66	
Carroll County 2002 Series A due 02/01/32 Var%	8,257.31	
Carroll County 2002 Series B due 02/01/32 Var%	578.63	
Carroll County 2002 Series C due 10/01/32 Var%	23,312.00	
Mercer County 2002 Series A due 02/01/32 Var%	1,784.11	
Muhlenburg County 2002 Series A due 02/01/32 Var%	578.63	
Carroll County 2004 Series A due 10/01/34 Var%	7,835.62	
Carroll County 2006 Series B due 10/01/34 Var%	8,344.11	
Carroll County 2007 Series A due 02/01/26 5.75%	342,604.17	
Trimble County 2007 Series A due 03/01/37 6.00%	178,540.00	
Carroll County 2008 Series A due 02/01/32 Var%	11,980.41	
First Mortgage Bond due 11/01/15 1.625%	1,692,708.33	
First Mortgage Bond due 11/01/20 3.250%	6,770,833.33	
First Mortgage Bond due 11/01/40 5.125%	16,015,625.00	
Customers' Deposits	346,311.16	
Interest Accrued on Tax Liabilities	16,537.70	
Other	13,583.99	

October 26, 2011

Kentucky Utilities Company
Summary Trial Balance
September 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Miscellaneous Current and Accrued Liabilities		$ 20,585,681.94
Vacation Pay Accrued	6,508,063.88	
Franchise Fee Payable	6,207,325.28	
Tax Collections Payable	4,121,155.36	
Customer Overpayments	3,298,011.36	
Derivative Liabilities - Non-Hedging	202,604.48	
Home Energy Assistance	192,240.29	
Escheated Deposits	(200.91)	
Other	56,482.20	
Accumulated Deferred Income Taxes		523,972,924.09
Federal	457,325,942.41	
State	66,646,981.68	
Investment Tax Credit		102,107,793.32
Advanced Coal Credit	99,316,947.00	
Job Development Credit	2,790,846.32	
Regulatory Liabilities		110,573,506.55
Deferred Taxes		
Federal	62,463,373.57	
State	19,576,939.37	
Postretirement Benefits	9,787,090.00	
Environmental Cost Recovery	6,952,837.15	
Asset Retirement Obligations	4,563,607.34	
DSM Cost Recovery	4,272,744.39	
Spare Parts	1,981,952.58	
MISO Schedule 10 Charges	974,962.15	
Customers' Advances for Construction		3,183,439.02
Line Extensions	2,512,234.76	
Other	671,204.26	
Asset Retirement Obligations	59,680,894.34	59,680,894.34
Other Deferred Credits	27,990,982.63	27,990,982.63
Miscellaneous Long-Term Liabilities		2,747,598.99
Workers' Compensation	2,747,598.99	
Accumulated Provision for Benefits		134,315,972.55
Pension Payable	70,301,999.50	
Postretirement Benefits - ASC 715	64,563,062.40	
Post Employment Benefits Payable	5,554,516.00	
Post Employment Medicare Subsidy	(382,793.62)	
Medicare Subsidy - ASC 715	(5,720,811.73)	
Total Liabilities and Stockholders Equity	$ 5,124,314,211.39	$ 5,124,314,211.39

October 26, 2011

Kentucky Utilities Company
Statement of Cash Flows
September 30, 2011

	Year to Date	
	2011	2010
Cash Flows from Operating Activities		
Net income	$ 141,869,561.98	129,017,965.81
Items not requiring (providing) cash currently:		
Depreciation	135,737,775.71	102,428,064.21
Amortization	5,322,045.10	4,943,299.63
Deferred income taxes - net	82,060,580.14	42,506,440.88
Investment Tax Credit	(2,039,699.00)	-
Gain on disposal of assets	(65,450.33)	(22,889.14)
Other	697,879.61	11,457,841.01
Change in receivables	26,268,716.37	(9,449,553.83)
Change in inventory	14,280,629.81	(3,378,073.35)
Change in allowance inventory	84,748.71	411,173.11
Change in payables and accrued expenses	(5,213,435.46)	(12,585,315.11)
Change in regulatory assets	(65,075,897.75)	24,753,673.31
Change in regulatory liabilities	55,499,525.27	5,061,995.05
Change in other deferred debits	(21,011,738.54)	(813,497.62)
Change in other deferred credits	19,848,580.46	20,507,223.08
Pension and postretirement funding	(46,279,600.00)	(16,795,900.00)
Other	11,810,082.86	5,919,933.21
Less: Allowance for other funds used during construction	(19,585.51)	(928,549.72)
Less: Undistributed earnings of subsidiary company	(2,145,926.00)	(3,662,566.00)
Net cash provided (used) by operating activities	351,628,793.43	299,371,264.53
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(152,528,493.78)	(265,916,506.49)
Less: Allowance for other funds used during construction	19,585.51	928,549.72
Proceeds received from sales of property	69,123.41	10,503.81
Change in derivatives	-	19,719.50
Other	(8,441,032.45)	-
Net cash provided (used) by investing activities	(160,880,817.31)	(264,957,733.46)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(2,137,067.20)	(514.80)
Net change in short-term debt	(10,434,000.00)	16,209,000.00
Dividends on common stock	(87,500,000.00)	(50,000,000.00)
Net cash provided (used) by financing activities	(100,071,067.20)	(33,791,514.80)
Net Increase (Decrease) in Cash and Cash Equivalents	90,676,908.92	622,016.27
Cash and Cash Equivalents at Beginning of Period	3,333,446.86	1,672,357.33
Cash and Cash Equivalents at End of Period	$ 94,010,355.78	$ 2,294,373.60

October 26, 2011

Kentucky Utilities Company
Analysis of Interest Charges
September 30, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Interest on Long-Term Debt						
Loan Agreement - Pollution Control Bonds						
Mercer County 2000 Series A due 05/01/23 Var%..............	$ 1,770.66	$ 3,710.96	$ 19,748.96	$ 30,829.15	$ 31,129.24	$ 44,637.46
Carroll County 2002 Series A due 02/01/32 Var%..............	10,321.63	10,579.69	144,325.27	109,696.17	183,060.10	165,662.41
Carroll County 2002 Series B due 02/01/32 Var%..............	1,084.93	1,213.15	16,163.37	12,578.63	20,605.01	18,996.16
Carroll County 2002 Series C due 10/01/32 Var%..............	22,560.00	46,240.00	206,309.43	557,218.63	336,890.76	616,629.29
Mercer County 2002 Series A due 02/01/32 Var%..............	3,345.20	3,740.55	48,657.54	38,784.13	62,352.60	58,571.53
Muhlenburg County 2002 Series A due 02/01/32 Var%.......	1,084.93	1,213.15	15,780.86	12,578.63	20,222.50	18,996.16
Carroll County 2004 Series A due 10/01/34 Var%..............	7,835.62	13,410.96	85,438.27	111,917.81	123,821.83	151,589.05
Carroll County 2006 Series B due 10/01/34 Var%..............	8,344.11	14,631.78	93,649.31	124,895.35	135,221.91	176,365.49
Carroll County 2007 Series A due 02/01/26 5.75%.............	85,651.04	85,651.05	770,859.38	770,859.39	1,027,812.49	1,027,812.51
Trimble County 2007 Series A due 03/01/37 6.00%............	44,635.00	44,635.00	401,715.00	401,715.00	535,620.00	535,620.00
Carroll County 2008 Series A due 02/01/32 Var%..............	11,980.41	21,013.77	133,749.19	180,987.46	192,989.21	257,781.67
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/01/15 1.625%.........................	338,541.66	-	3,046,874.99	-	3,554,687.50	-
First Mortgage Bond due 11/01/20 3.250%.........................	1,354,166.66	-	12,187,499.99	-	14,218,750.00	-
First Mortgage Bond due 11/01/40 5.125%.........................	3,203,125.00	-	28,828,125.00	-	33,632,812.50	-
Fidelia/PPL..	-	6,096,512.49	-	54,868,612.47	9,146,690.31	72,818,601.36
Total..	5,094,446.85	6,342,552.55	45,998,896.56	57,220,672.82	63,222,665.96	75,891,263.09
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense..................................	274,693.74	18,055.97	2,322,598.32	162,285.99	2,744,436.74	216,305.40
Amortization of Loss on Reacquired Debt...............................	50,414.39	50,414.39	453,729.51	453,574.33	604,972.68	604,723.60
Total..	325,108.13	68,470.36	2,776,327.83	615,860.32	3,349,409.42	821,029.00
Other Interest Charges						
Customers' Deposits..	109,716.38	99,837.99	1,029,893.37	1,049,260.57	1,344,202.67	1,331,867.38
Other Tax Deficiencies..	-	81,547.00	-	82,686.07	4,955.00	82,686.07
Interest on DSM Cost Recovery...	1,358.79	2,495.27	7,892.54	13,106.45	13,166.78	17,937.58
Interest on Debt to Associated Companies..............................	234.73	8,631.59	6,083.49	104,273.54	28,853.36	108,173.90
AFUDC Borrowed Funds..	(1,625.79)	(82,605.42)	(8,546.35)	(720,464.96)	(256,678.32)	(999,736.54)
Other Interest Expense..	264,700.40	315,043.48	3,090,253.14	1,572,635.96	3,880,405.11	2,024,149.91
Total..	374,384.51	424,949.91	4,125,576.19	2,101,497.63	5,014,904.60	2,565,078.30
Total Interest...	$ 5,793,939.49	$ 6,835,972.82	$ 52,900,800.58	$ 59,938,030.77	$ 71,586,979.98	$ 79,277,370.39

October 26, 2011

Kentucky Utilities Company
Analysis of Taxes Charged and Accrued
September 30, 2011

Kind of Taxes	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year
Taxes Charged to Accounts 408.1 and 409.1...........				
Property Taxes..	$ 1,989,753.00	$ 908,194.01	$ 13,948,496.77	$ 8,173,746.09
Unemployment..	3,031.57	4,701.39	92,115.14	97,739.77
FICA..	546,571.20	565,336.57	5,542,217.61	5,251,213.10
Public Service Commission Fee..............................	168,112.85	157,659.37	1,450,294.82	1,410,723.89
Federal Income..	(20,832,844.80)	(5,580,322.91)	(1,530,346.74)	29,989,123.45
State Income..	(2,523,082.85)	(646,498.83)	6,086,015.65	4,877,256.03
Miscellaneous..	2,756.26	3,347.71	54,879.53	60,171.20
Total Charged to Operating Expense..........	(20,645,702.77)	(4,587,582.69)	25,643,672.78	49,859,973.53
Taxes Charged to Other Accounts..........................	(575,375.71)	2,929,565.25	3,084,064.10	5,581,071.39
Taxes Accrued on Intercompany Accounts............	(35,519.71)	(277,267.68)	(2,258,172.49)	(2,337,120.85)
Total Taxes Charged.................................	$ (21,256,598.19)	$ (1,935,285.12)	$ 26,469,564.39	$ 53,103,924.07

Analysis of Taxes Accrued - Account 236

Kind of Taxes	Taxes Accrued At Beginning Of Year	Accruals To Date This Year	Payments To Date This Year	Taxes Accrued At End Of Month
Property Taxes..	$ 8,399,528.00	$ 13,949,999.77	$ 8,450,955.95	$ 13,898,571.82
Unemployment..	75,728.12	59,735.45	134,430.81	1,032.76
FICA..	639,011.24	4,675,341.31	4,884,614.02	429,738.53
Federal Income..	12,876,014.95	(1,835,173.45)	5,940,492.00	5,100,349.50
State Income..	2,021,178.48	6,481,307.15	7,978,002.00	524,483.63
Kentucky Sales and Use Tax..................................	581,659.33	3,022,967.38	3,273,078.77	331,547.94
Miscellaneous..	21,662.86	115,386.78	125,615.57	11,434.07
Totals...	$ 24,614,782.98	$ 26,469,564.39	$ 30,787,189.12	$ 20,297,158.25

October 26, 2011

Kentucky Utilities Company
Summary of Utility Plant
September 30, 2011

		Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101	**Utility Plant in Service**						
	Electric						
	Electric Distribution	$ 1,312,664,325.73	$ 66,222,016.65	$ (15,647,863.23)	$ 787,154.19	$ 51,361,307.61	$ 1,364,025,633.34
	Electric General Plant	125,243,994.19	13,659,467.70	(4,151,861.13)	(787,154.19)	8,720,452.38	133,964,446.57
	Electric Hydro Production	16,848,655.18	300,776.20	(15,190.72)	-	285,585.48	17,134,240.66
	Electric Intangible Plant	49,640,906.77	7,542,010.93	(1,381,084.50)	-	6,160,926.43	55,801,833.20
	Electric Other Production	519,412,128.33	3,002,985.62	(2,207,165.52)	-	795,820.10	520,207,948.43
	Electric Steam Production	1,814,421,935.78	725,692,456.73	(10,435,693.96)	124,492,063.50	839,748,826.27	2,654,170,762.05
	Electric Transmission	552,965,733.49	17,404,973.10	(2,252,716.15)	-	15,152,256.95	568,117,990.44
	Total 101 Accounts	4,391,197,679.47	833,824,686.93	(36,091,575.21)	124,492,063.50	922,225,175.22	5,313,422,854.69
102	**Electric Plant Purchased or Sold**						
	Electric						
	Electric Steam	483,341.17	-	-	-	-	483,341.17
	Total 102001	483,341.17	-	-	-	-	483,341.17
105	**Plant Held for Future Use**						
	Electric						
	Electric Distribution	792,599.21				-	792,599.21
	Electric Steam	120,828,152.53	-	-	(120,828,152.53)	(120,828,152.53)	-
	Total 105001	121,620,751.74	-	-	(120,828,152.53)	(120,828,152.53)	792,599.21
106	**Completed Construction Not Classified**						
	Electric						
	Electric Distribution	36,610,963.62	(10,254,101.65)	-	-	(10,254,101.65)	26,356,861.97
	Electric General Plant	769,342.30	1,045,028.33	-	-	1,045,028.33	1,814,370.63
	Electric Hydro Production	-	7,762.58	-	-	7,762.58	7,762.58
	Electric Intangible Plant	2,685,464.69	(1,672,018.20)	-	-	(1,672,018.20)	1,013,446.49
	Electric Other Production	3,737,695.33	(675,368.95)	-	-	(675,368.95)	3,062,326.38
	Electric Steam Production	910,748,505.16	(5,793,712.74)	-	-	(5,793,712.74)	904,954,792.42
	Electric Transmission	74,497,274.43	8,712,029.63	-	-	8,712,029.63	83,209,304.06
	Total 106 Accounts	1,029,049,245.53	(8,630,381.00)	-	-	(8,630,381.00)	1,020,418,864.53
121	**Nonutility Property**						
	Common						
	Non Utility Property	179,120.94	-	-	-	-	179,120.94
	Total 121001	179,120.94	-	-	-	-	179,120.94
107	**Construction Work In Progress**						
	Electric						
	Electric	954,430,277.48	(646,379,561.12)	-	-	(646,379,561.12)	308,050,716.36
	Total 107001	954,430,277.48	(646,379,561.12)	-	-	(646,379,561.12)	308,050,716.36
	Total Plant (Non-CWIP)	5,542,530,138.85	825,194,305.93	(36,091,575.21)	3,663,910.97	792,766,641.69	6,335,296,780.54
	Total Plant + CWIP	6,496,960,416.33	178,814,744.81	(36,091,575.21)	3,663,910.97	146,387,080.57	6,643,347,496.90
	Total Plant + CWIP - Nonutility (BS)	$ 6,496,781,295.39	$ 178,814,744.81	$ (36,091,575.21)	$ 3,663,910.97	$ 146,387,080.57	$ 6,643,168,375.96

Kentucky Utilities Company
Summary of Utility Plant - Reserve for Depreciation of Utility Plant
September 30, 2011

	Beginning Balance	Accruals	Retirements	Transfers/ Adjustments	ARO Settlements	RWIP Transfers Out	Cost of Removal	Salvage	Other Credits	Ending Balance
Life Reserve										
Electric Distribution.....................................	$ (398,692,068.83)	$ (20,709,125.49)	$ 15,647,863.23	$ (184,871.61)	$ -	$ -	$ -	$ -	$ -	$ (403,938,202.70)
Electric Distribution - ARO..........................	(790.87)	(3,325.04)	-	-	-	-	-	-	-	(4,115.91)
Electric General Plant..................................	(57,721,732.75)	(4,583,417.81)	4,151,861.13	181,198.53	-	-	-	-	-	(57,972,090.90)
Electric Hydro Production............................	(7,765,077.65)	(89,575.71)	15,190.72	-	-	-	-	-	-	(7,839,462.64)
Electric Hydro Production - ARO................	(121.57)	(729.72)	-	-	-	-	-	-	-	(851.29)
Electric Other Production.............................	(160,412,820.60)	(12,539,279.15)	2,207,165.52	-	-	-	-	-	-	(170,744,934.23)
Electric Other Production - ARO.................	(84.76)	(509.13)	-	-	-	-	-	-	-	(593.89)
Electric Steam Production............................	(1,067,997,942.05)	(66,530,938.12)	10,378,999.04	(282,823.63)	-	-	-	-	-	(1,124,432,704.76)
Electric Steam Production - ARO................	(485,952.30)	(2,251,856.66)	56,694.92	(105,352.11)	-	-	-	-	-	(2,786,466.15)
Electric Transmission...................................	(211,361,531.11)	(6,957,205.28)	2,252,716.15	-	-	-	-	-	-	(216,066,020.24)
Electric Transmission - ARO.......................	(156.99)	(942.29)	-	-	-	-	-	-	-	(1,099.28)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(1,904,438,279.48)	(113,666,904.40)	34,710,490.71	(391,848.82)	-	-	-	-	-	(1,983,786,541.99)
Cost of Removal										
Electric Distribution.....................................	(195,818,054.42)	(6,062,810.44)	-	40,000.02	-	-	3,481,124.30	-	-	(198,359,740.54)
Electric General Plant..................................	207,510.70	(33,835.53)	-	(0.02)	-	-	84,043.19	-	-	257,718.34
Electric Hydro Production............................	(374,056.75)	(3,900.06)	-	-	-	-	29,260.00	-	-	(348,696.81)
Electric Other Production.............................	(3,174,464.89)	(671,883.82)	-	-	-	-	69,863.95	-	-	(3,776,484.76)
Electric Steam Production............................	(113,988,699.33)	(18,817,498.19)	-	282,823.63	-	-	1,994,443.06	-	-	(130,528,930.83)
Electric Transmission...................................	(137,175,896.62)	(2,100,866.61)	-	-	-	-	2,148,245.59	-	-	(137,128,517.64)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(450,323,661.31)	(27,690,794.65)	-	322,823.63	-	-	7,806,980.09	-	-	(469,884,652.24)
Salvage										
Electric Distribution.....................................	48,221,606.07	1,478,977.79	-	-	-	-	-	(225,171.38)	-	49,475,412.48
Electric General Plant..................................	149,758.57	-	-	-	-	-	-	-	-	149,758.57
Electric Hydro Production............................	46,518.69	-	-	-	-	-	-	-	-	46,518.69
Electric Other Production.............................	618,891.61	-	-	-	-	-	-	-	-	618,891.61
Electric Steam Production............................	20,938,580.66	3,468,996.57	-	-	-	-	-	(1,360,313.33)	-	23,047,263.90
Electric Transmission...................................	23,009,336.80	487,539.66	-	-	-	-	-	(13,024.97)	-	23,483,851.49
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	92,984,692.40	5,435,514.02	-	-	-	-	-	(1,598,509.68)	-	96,821,696.74
Total Reserves										
Electric Distribution.....................................	(546,288,517.18)	(25,292,958.14)	15,647,863.23	(144,871.59)	-	-	3,481,124.30	(225,171.38)	-	(552,822,530.76)
Electric Distribution - ARO..........................	(790.87)	(3,325.04)	-	-	-	-	-	-	-	(4,115.91)
Electric General Plant..................................	(57,364,463.48)	(4,617,253.34)	4,151,861.13	181,198.51	-	-	84,043.19	-	-	(57,564,613.99)
Electric Hydro Production............................	(8,092,615.71)	(93,475.77)	15,190.72	-	-	-	29,260.00	-	-	(8,141,640.76)
Electric Hydro Production - ARO................	(121.57)	(729.72)	-	-	-	-	-	-	-	(851.29)
Electric Other Production.............................	(162,968,393.88)	(13,211,162.97)	2,207,165.52	-	-	-	69,863.95	-	-	(173,902,527.38)
Electric Other Production - ARO.................	(84.76)	(509.13)	-	-	-	-	-	-	-	(593.89)
Electric Steam Production............................	(1,161,048,060.72)	(81,879,439.74)	10,378,999.04	-	-	-	1,994,443.06	(1,360,313.33)	-	(1,231,914,371.69)
Electric Steam Production - ARO................	(485,952.30)	(2,251,856.66)	56,694.92	(105,352.11)	-	-	-	-	-	(2,786,466.15)
Electric Transmission...................................	(325,528,090.93)	(8,570,532.23)	2,252,716.15	-	-	-	2,148,245.59	(13,024.97)	-	(329,710,686.39)
Electric Transmission - ARO.......................	(156.99)	(942.29)	-	-	-	-	-	-	-	(1,099.28)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(2,261,777,248.39)	(135,922,185.03)	34,710,490.71	(69,025.19)	-	-	7,806,980.09	(1,598,509.68)	-	(2,356,849,497.49)
Retirement Work in Process										
Electric..	13,605,672.01		-	14,675.52	(161,732.61)	(6,046,737.80)	9,697,211.41	(698,925.30)	(259,025.33)	16,151,137.90
	13,605,672.01	-	-	14,675.52	(161,732.61)	(6,046,737.80)	9,697,211.41	(698,925.30)	(259,025.33)	16,151,137.90
YTD ACTIVITY	(2,248,171,576.38)	(135,922,185.03)	34,710,490.71	(54,349.67)	(161,732.61)	(6,046,737.80)	17,504,191.50	(2,297,434.98)	(259,025.33)	(2,340,698,359.59)
Amortization										
Electric..	(13,755,205.98)	(5,322,045.10)	1,381,084.50	-	-	-	-	-	-	(17,696,166.58)
	(13,755,205.98)	(5,322,045.10)	1,381,084.50	-	-	-	-	-	-	(17,696,166.58)
Depreciation & Amortization Total										
Depreciation & Amortization Total...............	(2,261,926,782.36)	(141,244,230.13)	36,091,575.21	(54,349.67)	(161,732.61)	(6,046,737.80)	17,504,191.50	(2,297,434.98)	(259,025.33)	(2,358,394,526.17)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)...............	$ 4,234,854,513.03									$ 4,284,773,849.79

October 26, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of September 30, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues....................................	$ 118,228,868.75	$ -	$ 118,228,868.75
Rate Refunds..	-	-	-
Total Operating Revenues....................................	118,228,868.75	-	118,228,868.75
Fuel for Electric Generation......................................	37,189,335.90	-	37,189,335.90
Power Purchased..	10,277,734.39	-	10,277,734.39
Other Operation Expenses..	19,991,779.38	-	19,991,779.38
Maintenance...	8,219,602.96	-	8,219,602.96
Depreciation...	15,311,906.86	-	15,311,906.86
Amortization Expense..	610,010.22	-	610,010.22
Regulatory Credits..	(499,374.55)	-	(499,374.55)
Taxes			
Federal Income...	(20,832,844.80)	-	(20,832,844.80)
State Income...	(2,523,082.85)	-	(2,523,082.85)
Deferred Federal Income - Net...............................	26,823,528.87	50,461.85	26,873,990.72
Deferred State Income - Net...................................	2,446,447.81	9,202.76	2,455,650.57
Property and Other...	2,710,224.88	-	2,710,224.88
Loss (Gain) from Disposition of Allowances............	-	-	-
Accretion Expense..	249,609.23	-	249,609.23
Total Operating Expenses......................................	99,974,878.30	59,664.61	100,034,542.91
Net Operating Income..	18,253,990.45	(59,664.61)	18,194,325.84
Other Income Less Deductions			
Amortization of Investment Tax Credit..............	233,343.00	-	233,343.00
Other Income Less Deductions...........................	169,822.96	12,331.33	182,154.29
AFUDC - Equity..	5,358.25	-	5,358.25
Total Other Income Less Deductions.....................	408,524.21	12,331.33	420,855.54
Income Before Interest Charges.............................	18,662,514.66	(47,333.28)	18,615,181.38
Interest on Long-Term Debt.....................................	5,094,446.85	(5,525.49)	5,088,921.36
Amortization of Debt Expense - Net.........................	325,108.13	-	325,108.13
Other Interest Expenses..	376,010.30	-	376,010.30
AFUDC - Borrowed Funds.......................................	(1,625.79)	-	(1,625.79)
Total Interest Charges..	5,793,939.49	(5,525.49)	5,788,414.00
Net Income...	$ 12,868,575.17	$ (41,807.79)	$ 12,826,767.38

Note: Purchase accounting is subject to change through October 31, 2011

October 26, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of September 30, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 1,190,676,956.48	$ -	$ 1,190,676,956.48
Rate Refunds	-	-	-
Total Operating Revenues	1,190,676,956.48	-	1,190,676,956.48
Fuel for Electric Generation	405,827,050.69	-	405,827,050.69
Power Purchased	82,968,379.82	-	82,968,379.82
Other Operation Expenses	176,106,124.34	31,612.30	176,137,736.64
Maintenance	89,454,697.00	-	89,454,697.00
Depreciation	135,737,775.71	-	135,737,775.71
Amortization Expense	5,322,045.10	-	5,322,045.10
Regulatory Credits	(4,329,248.45)	-	(4,329,248.45)
Taxes			
Federal Income	(1,530,346.74)	-	(1,530,346.74)
State Income	6,086,015.65	-	6,086,015.65
Deferred Federal Income - Net	75,504,027.65	6,017.56	75,510,045.21
Deferred State Income - Net	5,139,240.01	1,097.42	5,140,337.43
Property and Other	21,088,003.87	-	21,088,003.87
Loss (Gain) from Disposition of Allowances	(3,293.39)	-	(3,293.39)
Accretion Expense	2,071,885.61	-	2,071,885.61
Total Operating Expenses	999,442,356.87	38,727.28	999,481,084.15
Net Operating Income	191,234,599.61	(38,727.28)	191,195,872.33
Other Income Less Deductions			
Amortization of Investment Tax Credit	1,986,376.00	-	1,986,376.00
Other Income Less Deductions	1,521,255.09	861,431.79	2,382,686.88
AFUDC - Equity	28,131.86	-	28,131.86
Total Other Income Less Deductions	3,535,762.95	861,431.79	4,397,194.74
Income Before Interest Charges	194,770,362.56	822,704.51	195,593,067.07
Interest on Long-Term Debt	45,998,896.56	(49,729.42)	45,949,167.14
Amortization of Debt Expense - Net	2,776,327.83	-	2,776,327.83
Other Interest Expenses	4,134,122.54	-	4,134,122.54
AFUDC - Borrowed Funds	(8,546.35)	-	(8,546.35)
Total Interest Charges	52,900,800.58	(49,729.42)	52,851,071.16
Net Income	$ 141,869,561.98	$ 872,433.93	$ 142,741,995.91

Note: Purchase accounting is subject to change through October 31, 2011

October 26, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of September 30, 2011

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,478,582,672.63	$ 16,702,303.75	$ (1,402,495,087.26)	$ (14,979,223.24)	$ 76,087,585.37	$ 1,723,080.51
Add						
Net Income for Period...	12,868,575.17	-	(41,807.79)	-	12,826,767.38	-
Deductions:						
Common Dividends						
Common Stock Without Par Value..................	-	-	-	-	-	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	123,982.00	(123,982.00)	73,840.35	(73,840.35)	197,822.35	(197,822.35)
Balance at End of Period	$ 1,491,575,229.80	$ 16,578,321.75	$ (1,402,463,054.70)	$ (15,053,063.59)	$ 89,112,175.10	$ 1,525,258.16
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings................		16,578,321.75		(15,053,063.59)		1,525,258.16
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.........................		$ 6,448,967.16		$ (5,855,641.74)		$ 593,325.42

Note: Purchase accounting is subject to change through October 31, 2011.

October 26, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of September 30, 2011

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,439,351,593.82	$ 14,432,395.75	$ (1,404,000,051.78)	$ (14,388,500.44)	$ 35,351,542.04	$ 43,895.31
Add						
Net Income for Period ………………………………	141,869,561.98	-	872,433.93	-	142,741,995.91	-
Deductions:						
Common Dividends						
Common Stock Without Par Value...................	(87,500,000.00)	-	-	-	(87,500,000.00)	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc……………………….…………	(2,145,926.00)	2,145,926.00	664,563.15	(664,563.15)	(1,481,362.85)	1,481,362.85
Balance at End of Period …...……………………………	$ 1,491,575,229.80	$ 16,578,321.75	$ (1,402,463,054.70)	$ (15,053,063.59)	$ 89,112,175.10	$ 1,525,258.16
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings…………		16,578,321.75		(15,053,063.59)		1,525,258.16
Statutory Tax Rate…...…………………………………		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary…...…………….		$ 6,448,967.16		$ (5,855,641.74)		$ 593,325.42

Note: Purchase accounting is subject to change through October 31, 2011

October 26, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of September 30, 2011

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,392,973,602.96	$ 14,333,934.75	$ -	$ -	$ 1,392,973,602.96	$ 14,333,934.75
Add						
Net Income for Period...	188,346,013.84	-	808,268.31	-	189,154,282.15	-
Purchase Accounting Deductions:	-	-	(1,404,083,566.85)	(14,240,819.75)	(1,404,083,566.85)	(14,240,819.75)
Deductions:						
Common Dividends						
Common Stock Without Par Value....................	(87,500,000.00)	-	-	-	(87,500,000.00)	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	(2,244,387.00)	2,244,387.00	812,243.84	(812,243.84)	(1,432,143.16)	1,432,143.16
Balance at End of Period	$ 1,491,575,229.80	$ 16,578,321.75	$ (1,402,463,054.70)	$ (15,053,063.59)	$ 89,112,175.10	$ 1,525,258.16

Deferred Taxes Related to Undistributed Subsidiary Earnings		
Balance of Undistributed Subsidiary Earnings.................	16,578,321.75	(15,053,063.59)	1,525,258.16
Statutory Tax Rate...	38.9%	38.9%	38.9%
Deferred Taxes on Equity in Subsidiary...........................	$ 6,448,967.16	$ (5,855,641.74)	$ 593,325.42

Combined Balance of Retained Earnings	12 MONTHS 9/30/2011	12 MONTHS 9/30/2010
Retained Earnings at Beginning of Period........................	$ 1,407,307,537.71	$ 1,293,757,766.17
Net Income for Period	189,154,282.15	163,549,771.54
FIN 48 Adjustment...	-	-
Subtotal..	1,596,461,819.86	1,457,307,537.71
Deduct		
Purchase Accounting Adjustment................................	1,418,324,386.60	-
Dividends on Common Stock.....................................	87,500,000.00	50,000,000.00
Retained Earnings at End of Period.................................	$ 90,637,433.26	$ 1,407,307,537.71

Note: Purchase accounting is subject to change through October 31, 2011

October 26, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of September 30, 2011

Assets	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 6,643,168,375.96	$ -	$ 6,643,168,375.96
Less Reserves for Depreciation and Amortization.....	2,358,394,526.17	-	2,358,394,526.17
Total..	4,284,773,849.79	-	4,284,773,849.79
Investments			
Electric Energy, Inc...	13,829,384.55	16,909,439.16	30,738,823.71
Ohio Valley Electric Corporation.............................	250,000.00	-	250,000.00
Nonutility Property - Less Reserve...........................	179,120.94	-	179,120.94
Special Funds...	-	-	-
Total..	14,258,505.49	16,909,439.16	31,167,944.65
Current and Accrued Assets			
Cash..	33,388,033.43	-	33,388,033.43
Special Deposits..	91,321.13	-	91,321.13
Temporary Cash Investments.................................	60,622,322.35	-	60,622,322.35
Accounts Receivable-Less Reserve........................	159,643,815.32	-	159,643,815.32
Accounts Receivable from Assoc Companies..........	1,609,818.79	-	1,609,818.79
Materials & Supplies-At Average Cost			
Fuel...	79,497,725.17	-	79,497,725.17
Plant Materials & Operating Supplies..................	33,017,684.80	-	33,017,684.80
Stores Expense..	9,979,032.00	-	9,979,032.00
Allowance Inventory..	481,830.29	-	481,830.29
Prepayments..	8,400,992.34	-	8,400,992.34
Miscellaneous Current & Accrued Assets..............	137,330.72	-	137,330.72
Total..	386,869,906.34	-	386,869,906.34
Deferred Debits and Other			
Unamortized Debt Expense......................................	21,504,432.75	(4,463,920.34)	17,040,512.41
Unamortized Loss on Bonds....................................	11,926,360.54	-	11,926,360.54
Accumulated Deferred Income Taxes.......................	79,869,550.38	63,325,811.92	143,195,362.30
Deferred Regulatory Assets.....................................	280,492,761.03	14,266,421.90	294,759,182.93
Other Deferred Debits..	44,618,845.07	151,888,114.25	196,506,959.32
Goodwill...	-	607,404,368.23	607,404,368.23
Total..	438,411,949.77	832,420,795.96	1,270,832,745.73
Total Assets..	$ 5,124,314,211.39	$ 849,330,235.12	$ 5,973,644,446.51

Note: Purchase accounting is subject to change through October 31, 2011

October 26, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of September 30, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Proprietary Capital			
Common Stock...	$ 308,139,977.56	$ -	$ 308,139,977.56
Less: Common Stock Expense.....................................	321,288.87	-	321,288.87
Paid-In Capital..	315,858,083.00	2,032,588,750.94	2,348,446,833.94
Other Comprehensive Income.....................................	(2,471,334.43)	1,990,823.26	(480,511.17)
Retained Earnings..	1,491,575,229.80	(1,402,463,054.70)	89,112,175.10
Unappropriated Undistributed Subsidiary Earnings....	16,578,321.75	(15,053,063.59)	1,525,258.16
Total Proprietary Capital..	2,129,358,988.81	617,063,455.91	2,746,422,444.72
Pollution Control Bonds - Net of Reacquired Bonds...	350,779,405.00	1,100,674.60	351,880,079.60
First Mortgage Bonds..	1,489,653,343.75	-	1,489,653,343.75
Total Long-Term Debt...	1,840,432,748.75	1,100,674.60	1,841,533,423.35
Total Capitalization..	3,969,791,737.56	618,164,130.51	4,587,955,868.07
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Accounts Payable...	76,040,751.20	-	76,040,751.20
Accounts Payable to Associated Companies................	24,405,061.94	-	24,405,061.94
Customer Deposits...	23,179,523.85	-	23,179,523.85
Taxes Accrued..	20,297,158.25	-	20,297,158.25
Interest Accrued...	25,441,185.16	-	25,441,185.16
Dividends Declared..	-	-	-
Miscellaneous Current and Accrued Liabilities...........	20,585,681.94	-	20,585,681.94
Total..	189,949,362.34	-	189,949,362.34
Deferred Credits and Other			
Accumulated Deferred Income Taxes.........................	523,972,924.09	69,475,488.80	593,448,412.89
Investment Tax Credit..	102,107,793.32	-	102,107,793.32
Regulatory Liabilities...	110,573,506.55	151,888,114.25	262,461,620.80
Customer Advances for Construction.........................	3,183,439.02	-	3,183,439.02
Asset Retirement Obligations......................................	59,680,894.34	-	59,680,894.34
Other Deferred Credits...	27,990,982.63	9,802,501.56	37,793,484.19
Miscellaneous Long-Term Liabilities..........................	2,747,598.99	-	2,747,598.99
Accum Provision for Postretirement Benefits.............	134,315,972.55	-	134,315,972.55
Total..	964,573,111.49	231,166,104.61	1,195,739,216.10
Total Liabilities and Stockholders' Equity........................	$ 5,124,314,211.39	$ 849,330,235.12	$ 5,973,644,446.51

Note: Purchase accounting is subject to change through October 31, 2011

October 26, 2011

KENTUCKY UTILITIES COMPANY

Financial Reports

August 31, 2011

Index
Financial and Operating Reports

Kentucky Utilities Company
August 31, 2011

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2011 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows, unless otherwise noted.

Kentucky Utilities Company
Comparative Statement of Income
August 31, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 148,489,668.83	$ 151,438,340.57	$ (2,948,671.74)	(1.95)
Rate Refunds	-	-	-	-
Total Operating Revenues	148,489,668.83	151,438,340.57	(2,948,671.74)	(1.95)
Fuel for Electric Generation	53,286,923.89	53,393,017.83	(106,093.94)	(0.20)
Power Purchased	7,736,351.66	14,641,265.36	(6,904,913.70)	(47.16)
Other Operation Expenses	21,859,470.84	19,626,952.42	2,232,518.42	11.37
Maintenance	9,348,475.54	7,577,047.20	1,771,428.34	23.38
Depreciation	15,286,992.02	12,099,218.78	3,187,773.24	26.35
Amortization Expense	607,618.79	544,127.49	63,491.30	11.67
Regulatory Credits	(474,471.65)	(211,898.29)	(262,573.36)	(123.91)
Taxes				
Federal Income	10,712,248.19	11,625,196.16	(912,947.97)	(7.85)
State Income	1,953,601.50	2,120,096.56	(166,495.06)	(7.85)
Deferred Federal Income - Net	-	-	-	-
Deferred State Income - Net	-	-	-	-
Property and Other	2,221,248.95	1,643,394.79	577,854.16	35.16
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	-	-	-	-
Accretion Expense	230,559.05	187,153.36	43,405.69	23.19
Total Operating Expenses	122,769,018.78	123,245,571.66	(476,552.88)	(0.39)
Net Operating Income	25,720,650.05	28,192,768.91	(2,472,118.86)	(8.77)
Other Income Less Deductions				
Amortization of Investment Tax Credit	233,343.00	5,925.00	227,418.00	3,838.28
Other Income Less Deductions	421,793.54	345,525.29	76,268.25	22.07
AFUDC - Equity	4,596.47	104,896.97	(100,300.50)	(95.62)
Total Other Income Less Deductions	659,733.01	456,347.26	203,385.75	44.57
Income Before Interest Charges	26,380,383.06	28,649,116.17	(2,268,733.11)	(7.92)
Interest on Long-Term Debt	5,093,452.69	6,347,049.90	(1,253,597.21)	(19.75)
Amortization of Debt Expense - Net	324,095.50	68,470.36	255,625.14	373.34
Other Interest Expenses	410,154.45	270,638.66	139,515.79	51.55
AFUDC - Borrowed Funds	(1,394.81)	(83,207.02)	81,812.21	98.32
Total Interest Charges	5,826,307.83	6,602,951.90	(776,644.07)	(11.76)
Net Income	$ 20,554,075.23	$ 22,046,164.27	$ (1,492,089.04)	(6.77)

September 22, 2011

Kentucky Utilities Company
Comparative Statement of Income
August 31, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 1,072,448,087.73	$ 1,024,651,762.06	$ 47,796,325.67	4.66
Rate Refunds	-	(632,390.04)	632,390.04	100.00
Total Operating Revenues	1,072,448,087.73	1,024,019,372.02	48,428,715.71	4.73
Fuel for Electric Generation	368,637,714.79	351,852,167.76	16,785,547.03	4.77
Power Purchased	72,690,645.43	119,786,538.72	(47,095,893.29)	(39.32)
Other Operation Expenses	156,114,344.96	144,156,080.00	11,958,264.96	8.30
Maintenance	81,235,094.04	64,368,666.40	16,866,427.64	26.20
Depreciation	120,425,868.85	89,478,753.91	30,947,114.94	34.59
Amortization Expense	4,712,034.88	4,398,778.35	313,256.53	7.12
Regulatory Credits	(3,829,873.90)	(1,668,228.24)	(2,161,645.66)	(129.58)
Taxes				
Federal Income	19,302,498.06	35,569,446.36	(16,266,948.30)	(45.73)
State Income	8,609,098.50	5,523,754.86	3,085,343.64	55.86
Deferred Federal Income - Net	48,680,498.78	23,499,276.36	25,181,222.42	107.16
Deferred State Income - Net	2,692,792.20	5,096,830.24	(2,404,038.04)	(47.17)
Property and Other	18,377,778.99	13,354,355.00	5,023,423.99	37.62
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	(3,293.39)	(44,023.81)	40,730.42	92.52
Accretion Expense	1,822,276.38	1,470,154.93	352,121.45	23.95
Total Operating Expenses	899,467,478.57	856,842,550.84	42,624,927.73	4.97
Net Operating Income	172,980,609.16	167,176,821.18	5,803,787.98	3.47
Other Income Less Deductions				
Amortization of Investment Tax Credit	1,753,033.00	47,400.00	1,705,633.00	3,598.38
Other Income Less Deductions	1,351,432.13	1,603,929.32	(252,497.19)	(15.74)
AFUDC - Equity	22,773.61	103,925.01	(81,151.40)	(78.09)
Total Other Income Less Deductions	3,127,238.74	1,755,254.33	1,371,984.41	78.16
Income Before Interest Charges	176,107,847.90	168,932,075.51	7,175,772.39	4.25
Interest on Long-Term Debt	40,904,449.71	50,878,120.27	(9,973,670.56)	(19.60)
Amortization of Debt Expense - Net	2,451,219.70	547,389.96	1,903,829.74	347.80
Other Interest Expenses	3,758,112.24	2,314,407.26	1,443,704.98	62.38
AFUDC - Borrowed Funds	(6,920.56)	(637,859.54)	630,938.98	98.92
Total Interest Charges	47,106,861.09	53,102,057.95	(5,995,196.86)	(11.29)
Net Income	$ 129,000,986.81	$ 115,830,017.56	$ 13,170,969.25	11.37

September 22, 2011

Kentucky Utilities Company
Comparative Statement of Income
August 31, 2011

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues......................................	$ 1,560,138,421.59	$ 1,471,213,716.26	$ 88,924,705.33	6.04
Rate Refunds...	6.12	(1,101,620.83)	1,101,626.95	100.00
Total Operating Revenues.......................................	1,560,138,427.71	1,470,112,095.43	90,026,332.28	6.12
Fuel for Electric Generation.......................................	512,869,735.16	489,716,382.86	23,153,352.30	4.73
Power Purchased...	127,526,043.98	180,391,326.04	(52,865,282.06)	(29.31)
Other Operation Expenses...	228,605,492.73	208,996,080.46	19,609,412.27	9.38
Maintenance..	124,680,412.44	50,676,195.25	74,004,217.19	146.03
Depreciation..	170,229,155.63	132,393,225.84	37,835,929.79	28.58
Amortization Expense...	6,916,720.45	6,615,034.90	301,685.55	4.56
Regulatory Credits..	(7,311,203.01)	(2,483,931.72)	(4,827,271.29)	(194.34)
Taxes				
Federal Income...	45,392,500.98	31,442,306.36	13,950,194.62	44.37
State Income...	15,841,736.15	4,976,741.36	10,864,994.79	218.32
Deferred Federal Income - Net...............................	47,456,674.17	54,926,673.57	(7,469,999.40)	(13.60)
Deferred State Income - Net...................................	907,000.14	11,675,200.31	(10,768,200.17)	(92.23)
Property and Other...	24,916,902.96	18,503,277.39	6,413,625.57	34.66
Investment Tax Credit..	-	10,708,227.54	(10,708,227.54)	(100.00)
Loss (Gain) from Disposition of Allowances...........	(16,020.32)	(44,023.81)	28,003.49	63.61
Accretion Expense..	3,851,026.39	2,184,100.60	1,666,925.79	76.32
Total Operating Expenses......................................	1,301,866,177.85	1,200,676,816.95	101,189,360.90	8.43
Net Operating Income...	258,272,249.86	269,435,278.48	(11,163,028.62)	(4.14)
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	1,776,733.00	99,475.50	1,677,257.50	1,686.10
Other Income Less Deductions...........................	805,416.73	(891,802.90)	1,697,219.63	190.31
AFUDC - Equity...	440,000.64	970,790.37	(530,789.73)	(54.68)
Total Other Income Less Deductions......................	3,022,150.37	178,462.97	2,843,687.40	1,593.43
Income Before Interest Charges.............................	261,294,400.23	269,613,741.45	(8,319,341.22)	(3.09)
Interest on Long-Term Debt......................................	64,470,771.66	75,708,171.54	(11,237,399.88)	(14.84)
Amortization of Debt Expense - Net.........................	3,092,771.65	820,907.41	2,271,864.24	276.75
Other Interest Expenses..	5,403,127.95	3,470,326.84	1,932,801.11	55.70
AFUDC - Borrowed Funds.......................................	(337,657.95)	(1,007,111.48)	669,453.53	66.47
Total Interest Charges..	72,629,013.31	78,992,294.31	(6,363,281.00)	(8.06)
Net Income..	$ 188,665,386.92	$ 190,621,447.14	$ (1,956,060.22)	(1.03)

September 22, 2011

Kentucky Utilities Company
Analysis of Retained Earnings
August 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
Retained Earnings and Undistributed Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period..	$ 1,478,281,685.40	$ 15,949,215.75	$ 1,439,351,593.82	$ 14,432,395.75	$ 1,429,565,807.71	$ 14,553,781.75
Add:						
Net Income for Period...	20,554,075.23	-	129,000,986.81	-	188,665,386.92	-
Deduct:						
Common Dividends						
Common Stock Without Par Value	(19,500,000.00)	-	(87,500,000.00)	-	(137,500,000.00)	-
EE Inc..	(753,088.00)	753,088.00	(2,269,908.00)	2,269,908.00	(2,148,522.00)	2,148,522.00
Balance at End of Period..	$ 1,478,582,672.63	$ 16,702,303.75	$ 1,478,582,672.63	$ 16,702,303.75	$ 1,478,582,672.63	$ 16,702,303.75
Deferred Taxes Related to Undistributed Subsidiary Earnings		-		-		-
Balance of Undistributed Subsidiary Earnings.............................		16,702,303.75		16,702,303.75		16,702,303.75
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.......................................		$ 6,497,196.16		$ 6,497,196.16		$ 6,497,196.16

September 22, 2011

Kentucky Utilities Company
Comparative Balance Sheets as of August 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,617,428,284.38	$ 6,306,304,040.85
Less: Reserves for Depreciation and Amortization	2,345,266,761.50	2,233,819,303.67
Total	4,272,161,522.88	4,072,484,737.18
Investments		
Electric Energy, Inc	13,946,037.55	15,849,581.75
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	179,120.94	179,120.94
Total	14,375,158.49	16,278,702.69
Current and Accrued Assets		
Cash	38,149,431.99	4,510,613.58
Special Deposits	256,665.50	-
Temporary Cash Investments	49,715,396.92	269.25
Accounts Receivable-Less Reserve	186,539,676.89	222,492,353.04
Accounts Receivable from Associated Companies	63,189.83	2,450.21
Materials and Supplies-At Average Cost		
Fuel	74,480,640.86	103,479,165.84
Plant Materials and Operating Supplies	32,890,103.41	32,708,180.46
Stores Expense	9,837,806.88	8,429,661.64
Emission Allowances	490,495.67	593,996.01
Prepayments	8,071,702.33	6,265,327.84
Miscellaneous Current and Accrued Assets	161,940.18	115,901.12
Total	400,657,050.46	378,597,918.99
Deferred Debits and Other		
Unamortized Debt Expense	21,631,100.79	4,698,647.95
Unamortized Loss on Bonds	11,976,774.93	12,581,747.61
Accumulated Deferred Income Taxes	76,681,026.30	46,858,854.08
Deferred Regulatory Assets	283,333,140.25	230,646,976.86
Other Deferred Debits	44,460,143.95	41,487,233.29
Total	438,082,186.22	336,273,459.79
Total Assets	$ 5,125,275,918.05	$ 4,803,634,818.65

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	315,858,083.00	315,858,083.00
Other Comprehensive Income	(2,467,297.63)	-
Retained Earnings	1,478,582,672.63	1,429,565,807.71
Unappropriated Undistributed Subsidiary Earnings	16,702,303.75	14,553,781.75
Total Proprietary Capital	2,116,494,450.44	2,067,796,361.15
Pollution Control Bonds	350,779,405.00	350,779,405.00
First Mortgage Bonds	1,489,600,406.25	-
LT Notes Payable to Associated Companies	-	1,298,000,000.00
Total Long-Term Debt	1,840,379,811.25	1,648,779,405.00
Total Capitalization	3,956,874,261.69	3,716,575,766.15
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	93,299,954.00
Accounts Payable	78,525,380.23	81,939,486.21
Accounts Payable to Associated Companies	34,247,202.13	52,404,259.96
Customer Deposits	23,264,959.01	22,401,207.52
Taxes Accrued	41,215,179.56	31,164,228.57
Interest Accrued	20,293,199.13	711,395.74
Dividends Declared	19,500,000.00	-
Miscellaneous Current and Accrued Liabilities	19,827,702.88	19,153,979.79
Total	236,873,622.94	301,074,511.79
Deferred Credits and Other		
Accumulated Deferred Income Taxes	491,559,670.98	409,153,631.96
Investment Tax Credit	102,341,136.32	104,117,869.32
Regulatory Liabilities	115,465,105.22	54,487,018.84
Customer Advances for Construction	3,240,757.14	3,116,287.87
Asset Retirement Obligations	55,625,808.75	35,820,626.34
Other Deferred Credits	26,164,116.81	27,187,578.67
Miscellaneous Long-Term Liabilities	2,805,389.46	2,660,205.61
Accum Provision for Postretirement Benefits	134,326,048.74	149,441,322.10
Total	931,528,033.42	785,984,540.71
Total Liabilities and Stockholders Equity	$ 5,125,275,918.05	$ 4,803,634,818.65

September 22, 2011

Kentucky Utilities Company
Statement of Capitalization and Short-Term Debt
August 31, 2011

	Authorized Shares	Issued and Outstanding Shares	Issued and Outstanding Amount	Percent of Total Capital
Proprietary Capital				
Common Stock - Without Par..	80,000,000	37,817,878	$ 308,139,977.56	
Less: Common Stock Expense..			321,288.87	
Paid-In Capital..			315,858,083.00	
Other Comprehensive Income..			(2,467,297.63)	
Retained Earnings..			1,478,582,672.63	
Unappropriated Undistributed Subsidiary Earnings.............			16,702,303.75	
Total Proprietary Capital...			2,116,494,450.44	53.48
Long-Term Debt				
Pollution Control Bonds				
Mercer County 2000 Series A due 05/01/23 Var%..........			12,900,000.00	
Carroll County 2002 Series A due 02/01/32 Var%..........			20,930,000.00	
Carroll County 2002 Series B due 02/01/32 Var%..........			2,400,000.00	
Carroll County 2002 Series C due 10/01/32 Var%..........			96,000,000.00	
Mercer County 2002 Series A due 02/01/32 Var%..........			7,400,000.00	
Muhlenburg County 2002 Series A due 02/01/32 Var%...			2,400,000.00	
Carroll County 2004 Series A due 10/01/34 Var%..........			50,000,000.00	
Carroll County 2006 Series B due 10/01/34 Var%..........			54,000,000.00	
Carroll County 2007 Series A due 02/01/26 5.75%.........			17,875,000.00	
Trimble County 2007 Series A due 03/01/37 6.00%........			8,927,000.00	
Carroll County 2008 Series A due 02/01/32 Var%..........			77,947,405.00	
Total Pollution Control Bonds..			350,779,405.00	8.87
First Mortgage Bonds				
First Mortgage Bond due 11/01/15 1.625%.......................			250,000,000.00	
First Mortgage Bond due 11/01/20 3.250%......................			500,000,000.00	
First Mortgage Bond due 11/01/40 5.125%......................			750,000,000.00	
Total First Mortgage Bonds..			1,500,000,000.00	37.91
Less: First Mortgage Bonds Debt Discount				
First Mortgage Bond due 11/01/15 1.625%.......................			(736,458.34)	
First Mortgage Bond due 11/01/20 3.250%......................			(1,740,375.00)	
First Mortgage Bond due 11/01/40 5.125%......................			(7,922,760.41)	
			(10,399,593.75)	(0.26)
Total First Mortgage Bonds - Net of Debt Discount............			1,489,600,406.25	37.65
Total Capitalization...			$ 3,956,874,261.69	100.00

September 22, 2011

Kentucky Utilities Company
Summary Trial Balance
August 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 6,617,428,284.38	$ 6,617,428,284.38
Reserves for Depreciation and Amortization		(2,345,266,761.50)
Depreciation of Plant	(2,328,180,605.14)	
Amortization of Plant	(17,086,156.36)	
Investments		14,375,158.49
Electric Energy, Inc	13,946,037.55	
Ohio Valley Electric Corporation	250,000.00	
Nonutility Property Reserve	179,120.94	
Cash	38,149,431.99	38,149,431.99
Special Deposits		256,665.50
MAN Margin Call	256,665.50	
Temporary Cash Investments	49,715,396.92	49,715,396.92
Accounts Receivable - Less Reserve		186,539,676.89
Unbilled Revenues	92,491,443.00	
Customers - Active	82,918,971.32	
Bechtel Liquidated Damages	6,310,710.00	
IMPA	1,745,173.01	
IMEA	1,642,627.79	
Transmission Sales	1,168,249.50	
Damage Claims	363,820.73	
Mutual Aid	330,195.55	
Sundry Accounts Receivable	5,078.22	
IMEA/IMPA Net Portion of Bechtel Liquidated Damages	(1,577,677.50)	
Other	3,516,497.21	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	5,120,392.35	
Accrual	(4,336,949.35)	
Reserve	(2,079,731.00)	
Recoveries	(783,308.81)	
A/R Miscellaneous	(295,815.13)	
Accounts Receivable from Associated Companies		63,189.83
PPL Energy Funding	55,646.10	
LG&E - KU Energy Services/Louisville Gas and Electric Company	7,543.73	
Fuel		74,480,640.86
Coal 1,207,734.92 Tons @ $55.52 MMBtu 27,812,531.38 @ 241.08¢	67,050,787.46	
Fuel Oil 2,940,494 Gallons @ 250.63¢	7,369,821.58	
Gas Pipeline 12,596.70 Mcf @ $4.77	60,031.82	
Plant Materials and Operating Supplies		32,890,103.41
Regular Materials and Supplies	32,275,873.08	
Limestone 52,426.85 Tons @ $11.72	614,230.30	
Other Reagents	0.03	
Stores Expense Undistributed	9,837,806.88	9,837,806.88

September 22, 2011

Kentucky Utilities Company
Summary Trial Balance
August 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Emission Allowances	$ 490,495.67	$ 490,495.67
Prepayments		8,071,702.33
Insurance	3,398,103.33	
Taxes	1,681,128.56	
Lease	645,666.60	
Risk Management and Workers Compensation	75,000.00	
Other	2,271,803.84	
Miscellaneous Current Assets		161,940.18
Derivative Asset - Non-Hedging	161,940.18	
Unamortized Debt Expense		21,631,100.79
Carroll County 2002 Series A due 02/01/32 Var%	83,712.34	
Carroll County 2002 Series B due 02/01/32 Var%	58,181.62	
Carroll County 2002 Series C due 10/01/32 Var%	1,552,956.02	
Mercer County 2002 Series A due 02/01/32 Var%	23,368.40	
Muhlenburg County 2002 Series A due 02/01/32 Var%	64,767.11	
Carroll County 2006 Series B due 10/01/34 Var%	1,106,154.10	
Carroll County 2007 Series A due 02/01/26 5.75%	480,682.29	
Trimble County 2007 Series A due 03/01/37 6.00%	409,827.78	
Carroll County 2008 Series A due 02/01/32 Var%	702,326.65	
First Mortgage Bond due 11/01/15 1.625%	1,893,516.48	
First Mortgage Bond due 11/01/20 3.250%	3,807,926.99	
First Mortgage Bond due 11/01/40 5.125%	7,249,549.28	
Revolving Credit Agreement	4,198,131.73	
Unamortized Loss on Bonds		11,976,774.93
Refinanced and Called Bonds	11,976,774.93	
Accumulated Deferred Income Taxes		76,681,026.30
Federal	64,935,848.93	
State	11,745,177.37	
Regulatory Assets		283,333,140.25
Pension and Postretirement Benefits	117,274,368.11	
ASC 740 - Deferred Taxes	77,275,037.46	
2009 Winter Storm	51,036,109.68	
Fuel Adjustment Clause	6,494,000.00	
Virginia Mountain Snowstorm	6,041,670.12	
FERC Jurisdictional Pension Expense	5,531,187.15	
Asset Retirement Obligations	5,202,948.56	
VA Fuel Component Non-Current	4,991,000.00	
MISO Exit Fee	4,169,516.65	
2008 Wind Storm	1,957,668.74	
Rate Case Expenses	1,517,364.86	
EKPC FERC Transmission Cost	836,742.66	
KCCS Funding	672,262.87	
CMRG Funding	196,343.29	
General Management Audit	136,920.10	
Other Deferred Debits	44,460,143.95	44,460,143.95
Total Assets	$ 5,125,275,918.05	$ 5,125,275,918.05

September 22, 2011

Kentucky Utilities Company
Summary Trial Balance
August 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 2,116,494,450.44
Common Stock	308,139,977.56	
Less: Common Stock Expense	321,288.87	
Paid-In Capital	315,858,083.00	
Other Comprehensive Income	(2,467,297.63)	
Retained Earnings	1,478,582,672.63	
Unappropriated Undistributed Subsidiary Earnings	16,702,303.75	
Bonds		1,840,379,811.25
Pollution Control Bonds - Net of Reacquired Bonds	350,779,405.00	
First Mortgage Bonds	1,489,600,406.25	
Accounts Payable		78,525,380.23
Regular	74,365,374.37	
Salaries and Wages Accrued	4,108,255.96	
Employee Withholdings Payable	51,749.90	
Accounts Payable to Associated Companies		34,247,202.13
LG&E - KU Energy Services/Louisville Gas and Electric Company	34,247,202.13	
Customers' Deposits	23,264,959.01	23,264,959.01
Taxes Accrued	41,215,179.56	41,215,179.56
Interest Accrued		20,293,199.13
Mercer County 2000 Series A due 05/01/23 Var%	2,134.68	
Carroll County 2002 Series A due 02/01/32 Var%	7,569.21	
Carroll County 2002 Series B due 02/01/32 Var%	506.30	
Carroll County 2002 Series C due 10/01/32 Var%	752.00	
Mercer County 2002 Series A due 02/01/32 Var%	1,561.10	
Muhlenburg County 2002 Series A due 02/01/32 Var%	506.30	
Carroll County 2004 Series A due 10/01/34 Var%	8,643.84	
Carroll County 2006 Series B due 10/01/34 Var%	9,364.93	
Carroll County 2007 Series A due 02/01/26 5.75%	256,953.13	
Trimble County 2007 Series A due 03/01/37 6.00%	133,905.00	
Carroll County 2008 Series A due 02/01/32 Var%	14,073.24	
First Mortgage Bond due 11/01/15 1.625%	1,354,166.67	
First Mortgage Bond due 11/01/20 3.250%	5,416,666.67	
First Mortgage Bond due 11/01/40 5.125%	12,812,500.00	
Customers' Deposits	245,133.16	
Other	28,762.90	
Dividends Declared		19,500,000.00
Dividend Payable to LG&E and KU Energy LLC	19,500,000.00	

September 22, 2011

Kentucky Utilities Company
Summary Trial Balance
August 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Miscellaneous Current and Accrued Liabilities		$ 19,827,702.88
Vacation Pay Accrued	6,700,744.77	
Tax Collections Payable	4,899,752.83	
Franchise Fee Payable	4,379,501.86	
Customer Overpayments	3,261,031.29	
Derivative Liabilities - Non-Hedging	282,926.46	
Home Energy Assistance	243,592.79	
Escheated Deposits	(200.91)	
Other	60,353.79	
Accumulated Deferred Income Taxes		491,559,670.98
Federal	427,861,146.32	
State	63,698,524.66	
Investment Tax Credit		102,341,136.32
Advanced Coal Credit	99,544,365.00	
Job Development Credit	2,796,771.32	
Regulatory Liabilities		115,465,105.22
Deferred Taxes		
Federal	62,438,640.72	
State	19,612,490.70	
Environmental Cost Recovery	11,375,213.15	
Postretirement Benefits	9,787,090.00	
DSM Cost Recovery	4,864,650.48	
Asset Retirement Obligations	4,542,975.38	
Spare Parts	1,906,297.00	
MISO Schedule 10 Charges	937,747.79	
Customers' Advances for Construction		3,240,757.14
Line Extensions	2,586,636.58	
Other	654,120.56	
Asset Retirement Obligations	55,625,808.75	55,625,808.75
Other Deferred Credits	26,164,116.81	26,164,116.81
Miscellaneous Long-Term Liabilities		2,805,389.46
Workers' Compensation	2,805,389.46	
Accumulated Provision for Benefits		134,326,048.74
Pension Payable	70,301,999.50	
Postretirement Benefits - ASC 715	64,573,138.59	
Post Employment Benefits Payable	5,554,516.00	
Post Employment Medicare Subsidy	(382,793.62)	
Medicare Subsidy - ASC 715	(5,720,811.73)	
Total Liabilities and Stockholders Equity	$ 5,125,275,918.05	$ 5,125,275,918.05

September 22, 2011

Kentucky Utilities Company
Statement of Cash Flows
August 31, 2011

	Year to Date	
	2011	2010
Cash Flows from Operating Activities		
Net income	$ 129,000,986.81	115,830,017.56
Items not requiring (providing) cash currently:		
Depreciation	120,425,868.85	89,478,753.91
Amortization	4,712,034.88	4,398,778.35
Deferred income taxes - net	52,829,926.11	28,596,106.60
Investment Tax Credit	(1,800,431.00)	-
Gain on disposal of assets	(70,337.29)	(13,424.53)
Other	(4,001,276.89)	14,981,105.50
Change in receivables	6,254,129.34	(40,346,595.16)
Change in inventory	19,509,613.47	(8,922,294.72)
Change in allowance inventory	76,083.33	381,079.89
Change in payables and accrued expenses	25,704,653.60	(20,568,616.99)
Change in regulatory assets	(67,270,694.45)	23,024,772.19
Change in regulatory liabilities	60,315,468.36	10,242,575.44
Change in other deferred debits	(19,335,501.37)	(794,476.65)
Change in other deferred credits	17,800,753.41	17,320,496.66
Pension and postretirement funding	(46,279,600.00)	(16,795,900.00)
Other	11,118,381.90	(918,222.82)
Less: Allowance for other funds used during construction	(15,853.05)	(741,784.55)
Less: Undistributed earnings of subsidiary company	(2,269,908.00)	(3,882,413.00)
Net cash provided (used) by operating activities	306,704,298.01	211,269,957.68
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(134,778,118.27)	(224,517,004.42)
Less: Allowance for other funds used during construction	15,853.05	741,784.55
Proceeds received from sales of property	118,419.01	-
Change in derivatives	-	19,302.49
Other	(7,053,090.75)	-
Net cash provided (used) by investing activities	(141,696,936.96)	(223,755,917.38)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(2,041,979.00)	(514.80)
Net change in short-term debt	(10,434,000.00)	15,325,000.00
Dividends on common stock	(68,000,000.00)	-
Net cash provided (used) by financing activities	(80,475,979.00)	15,324,485.20
Net Increase (Decrease) in Cash and Cash Equivalents	84,531,382.05	2,838,525.50
Cash and Cash Equivalents at Beginning of Period	3,333,446.86	1,672,357.33
Cash and Cash Equivalents at End of Period	$ 87,864,828.91	$ 4,510,882.83

September 22, 2011

Kentucky Utilities Company
Analysis of Interest Charges
August 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Interest on Long-Term Debt						
Loan Agreement - Pollution Control Bonds						
Mercer County 2000 Series A due 05/01/23 Var%..............	$ 2,134.68	$ 4,078.52	$ 17,978.30	$ 27,118.19	$ 33,069.54	$ 44,994.42
Carroll County 2002 Series A due 02/01/32 Var%..............	10,665.70	10,665.70	134,003.64	99,116.48	183,318.16	174,005.74
Carroll County 2002 Series B due 02/01/32 Var%..............	1,121.10	1,223.01	15,078.44	11,365.48	20,733.23	19,952.87
Carroll County 2002 Series C due 10/01/32 Var%..............	16,752.00	49,114.67	183,749.43	510,978.63	360,570.76	595,509.29
Mercer County 2002 Series A due 02/01/32 Var%..............	3,456.71	3,770.96	45,312.34	35,043.58	62,747.95	61,521.39
Muhlenburg County 2002 Series A due 02/01/32 Var%.......	1,121.10	1,223.01	14,695.93	11,365.48	20,350.72	19,952.87
Carroll County 2004 Series A due 10/01/34 Var%..............	8,643.85	14,068.49	77,602.65	98,506.85	129,397.17	152,575.35
Carroll County 2006 Series B due 10/01/34 Var%..............	9,364.93	14,409.86	85,305.20	110,263.57	141,509.58	180,507.96
Carroll County 2007 Series A due 02/01/26 5.75%.............	85,651.05	85,651.05	685,208.34	685,208.34	1,027,812.50	1,027,812.50
Trimble County 2007 Series A due 03/01/37 6.00%............	44,635.00	44,635.00	357,080.00	357,080.00	535,620.00	535,620.00
Carroll County 2008 Series A due 02/01/32 Var%..............	14,073.24	21,697.14	121,768.78	159,973.69	202,022.57	262,326.12
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/01/15 1.625%.........................	338,541.66	-	2,708,333.33	-	3,216,145.84	-
First Mortgage Bond due 11/01/20 3.250%.........................	1,354,166.67	-	10,833,333.33	-	12,864,583.34	-
First Mortgage Bond due 11/01/40 5.125%.........................	3,203,125.00	-	25,625,000.00	-	30,429,687.50	-
Fidelia/PPL..	-	6,096,512.49	-	48,772,099.98	15,243,202.80	72,633,393.03
Total...	5,093,452.69	6,347,049.90	40,904,449.71	50,878,120.27	64,470,771.66	75,708,171.54
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense..................................	273,681.11	18,055.97	2,047,904.58	144,230.02	2,487,798.97	216,239.56
Amortization of Loss on Reacquired Debt...............................	50,414.39	50,414.39	403,315.12	403,159.94	604,972.68	604,667.85
Total...	324,095.50	68,470.36	2,451,219.70	547,389.96	3,092,771.65	820,907.41
Other Interest Charges						
Customers' Deposits..	121,982.79	102,915.77	920,176.99	949,422.58	1,334,324.28	1,313,630.26
Other Tax Deficiencies..	-	-	-	1,139.07	86,502.00	1,139.07
Interest on DSM Cost Recovery..	1,435.74	862.10	6,533.75	10,611.18	14,303.26	60,126.50
Interest on Debt to Associated Companies..............................	60.00	17,091.26	5,848.76	95,641.95	37,250.22	100,358.48
AFUDC Borrowed Funds..	(1,394.81)	(83,207.02)	(6,920.56)	(637,859.54)	(337,657.95)	(1,007,111.48)
Other Interest Expense..	286,675.92	149,769.53	2,825,552.74	1,257,592.48	3,930,748.19	1,995,072.53
Total...	408,759.64	187,431.64	3,751,191.68	1,676,547.72	5,065,470.00	2,463,215.36
Total Interest..	$ 5,826,307.83	$ 6,602,951.90	$ 47,106,861.09	$ 53,102,057.95	$ 72,629,013.31	$ 78,992,294.31

September 22, 2011

Kentucky Utilities Company
Analysis of Taxes Charged and Accrued
August 31, 2011

Kind of Taxes	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year
Taxes Charged to Accounts 408.1 and 409.1...........				
Property Taxes..	$ 1,494,264.00	$ 908,194.01	$ 11,958,743.77	$ 7,265,552.08
Unemployment..	3,180.17	4,322.55	89,083.57	93,038.38
FICA..	553,132.94	561,620.20	4,995,646.41	4,685,876.53
Public Service Commission Fee..............................	168,112.85	157,659.37	1,282,181.97	1,253,064.52
Federal Income..	10,712,248.19	11,625,196.16	19,302,498.06	35,569,446.36
State Income..	1,953,601.50	2,120,096.56	8,609,098.50	5,523,754.86
Miscellaneous..	2,558.99	11,598.66	52,123.27	56,823.49
Total Charged to Operating Expense..........	14,887,098.64	15,388,687.51	46,289,375.55	54,447,556.22
Taxes Charged to Other Accounts..........................	538,564.19	660,942.25	3,659,439.81	2,651,506.14
Taxes Accrued on Intercompany Accounts............	(37,992.67)	(253,484.01)	(2,222,652.78)	(2,059,853.17)
Total Taxes Charged.................................	$ 15,387,670.16	$ 15,796,145.75	$ 47,726,162.58	$ 55,039,209.19

Analysis of Taxes Accrued - Account 236

Kind of Taxes	Taxes Accrued At Beginning Of Year	Accruals To Date This Year	Payments To Date This Year	Taxes Accrued At End Of Month
Property Taxes..	$ 8,399,528.00	$ 11,960,079.77	$ 8,403,240.41	$ 11,956,367.36
Unemployment..	75,728.12	59,347.48	134,430.81	644.79
FICA..	639,011.24	4,144,379.43	4,165,238.08	618,152.59
Federal Income..	12,876,014.95	19,664,699.46	9,041,229.00	23,499,485.41
State Income..	2,021,178.48	9,126,036.47	6,250,451.00	4,896,763.95
Kentucky Sales and Use Tax..................................	581,659.33	2,657,070.61	3,006,398.55	232,331.39
Miscellaneous..	21,662.86	114,549.36	124,778.15	11,434.07
Totals...	$ 24,614,782.98	$ 47,726,162.58	$ 31,125,766.00	$ 41,215,179.56

September 22, 2011

Kentucky Utilities Company
Summary of Utility Plant
August 31, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant in Service**						
Electric						
Electric Distribution	$ 1,312,664,325.73	$ 58,399,466.72	$ (14,392,927.93)	$ 787,154.19	$ 44,793,692.98	$ 1,357,458,018.71
Electric General Plant	125,243,994.19	13,392,924.08	(4,151,861.13)	(787,154.19)	8,453,908.76	133,697,902.95
Electric Hydro Production	16,848,655.18	300,776.20	(15,190.72)	-	285,585.48	17,134,240.66
Electric Intangible Plant	49,640,906.77	7,515,636.01	(1,381,084.50)	-	6,134,551.51	55,775,458.28
Electric Other Production	519,412,128.33	2,806,295.97	(2,081,136.52)	-	725,159.45	520,137,287.78
Electric Steam Production	1,814,421,935.78	725,396,873.56	(10,379,007.02)	120,828,152.53	835,846,019.07	2,650,267,954.85
Electric Transmission	552,965,733.49	15,309,644.53	(2,144,365.09)	-	13,165,279.44	566,131,012.93
Total 101 Accounts	4,391,197,679.47	823,121,617.07	(34,545,572.91)	120,828,152.53	909,404,196.69	5,300,601,876.16
102 **Electric Plant Purchased or Sold**						
Electric						
Electric Steam	483,341.17	-	-	-	-	483,341.17
Total 102001	483,341.17	-	-	-	-	483,341.17
105 **Plant Held for Future Use**						
Electric						
Electric Distribution	792,599.21				-	792,599.21
Electric Steam	120,828,152.53	-	-	(120,828,152.53)	(120,828,152.53)	-
Total 105001	121,620,751.74	-	-	(120,828,152.53)	(120,828,152.53)	792,599.21
106 **Completed Construction Not Classified**						
Electric						
Electric Distribution	36,610,963.62	(5,524,448.19)	-	-	(5,524,448.19)	31,086,515.43
Electric General Plant	769,342.30	94,838.13	-	-	94,838.13	864,180.43
Electric Hydro Production	-	7,762.58	-	-	7,762.58	7,762.58
Electric Intangible Plant	2,685,464.69	(1,862,907.44)	-	-	(1,862,907.44)	822,557.25
Electric Other Production	3,737,695.33	(531,440.46)	-	-	(531,440.46)	3,206,254.87
Electric Steam Production	910,748,505.16	(7,034,606.90)	-	-	(7,034,606.90)	903,713,898.26
Electric Transmission	74,497,274.43	7,831,061.30	-	-	7,831,061.30	82,328,335.73
Total 106 Accounts	1,029,049,245.53	(7,019,740.98)	-	-	(7,019,740.98)	1,022,029,504.55
121 **Nonutility Property**						
Common						
Non Utility Property	179,120.94	-	-	-	-	179,120.94
Total 121001	179,120.94	-	-	-	-	179,120.94
107 **Construction Work In Progress**						
Electric						
Electric	954,430,277.48	(660,909,314.19)	-	-	(660,909,314.19)	293,520,963.29
Total 107001	954,430,277.48	(660,909,314.19)	-	-	(660,909,314.19)	293,520,963.29
Total Plant (Non-CWIP)	5,542,530,138.85	816,101,876.09	(34,545,572.91)	-	781,556,303.18	6,324,086,442.03
Total Plant + CWIP	6,496,960,416.33	155,192,561.90	(34,545,572.91)	-	120,646,988.99	6,617,607,405.32
Total Plant + CWIP - Nonutility (BS)	$ 6,496,781,295.39	$ 155,192,561.90	$ (34,545,572.91)	$ -	$ 120,646,988.99	$ 6,617,428,284.38

September 22, 2011

Kentucky Utilities Company
Summary of Utility Plant - Reserve for Depreciation of Utility Plant
August 31, 2011

	Beginning Balance	Accruals	Retirements	Transfers/ Adjustments	ARO Settlements	RWIP Transfers Out	Cost of Removal	Salvage	Other Credits	Ending Balance
Life Reserve										
Electric Distribution.....................................	$ (398,692,068.83)	$ (18,377,282.74)	$ 14,392,927.93	$ (184,871.61)	$ -	$ -	$ -	$ -	$ -	$ (402,861,295.25)
Electric Distribution - ARO..........................	(790.87)	(2,955.59)	-	-	-	-	-	-	-	(3,746.46)
Electric General Plant..................................	(57,721,732.75)	(4,029,750.64)	4,151,861.13	181,198.53	-	-	-	-	-	(57,418,423.73)
Electric Hydro Production............................	(7,765,077.65)	(79,571.89)	15,190.72	-	-	-	-	-	-	(7,829,458.82)
Electric Hydro Production - ARO................	(121.57)	(648.64)	-	-	-	-	-	-	-	(770.21)
Electric Other Production.............................	(160,412,820.60)	(11,149,108.27)	2,081,136.52	-	-	-	-	-	-	(169,480,792.35)
Electric Other Production - ARO.................	(84.76)	(452.56)	-	-	-	-	-	-	-	(537.32)
Electric Steam Production............................	(1,067,997,942.05)	(59,028,189.63)	10,322,312.10	(282,823.63)	-	-	-	-	-	(1,116,986,643.21)
Electric Steam Production - ARO................	(485,952.30)	(2,002,703.14)	56,694.92	-	-	-	-	-	-	(2,431,960.52)
Electric Transmission...................................	(211,361,531.11)	(6,167,045.56)	2,144,365.09	-	-	-	-	-	-	(215,384,211.58)
Electric Transmission - ARO.......................	(156.99)	(837.59)	-	-	-	-	-	-	-	(994.58)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(1,904,438,279.48)	(100,838,546.25)	33,164,488.41	(286,496.71)	-	-	-	-	-	(1,972,398,834.03)
Cost of Removal										
Electric Distribution.....................................	(195,818,054.42)	(5,377,903.17)	-	40,000.02	-	-	3,024,696.41	-	-	(198,131,261.16)
Electric General Plant..................................	207,510.70	(29,932.08)	-	(0.02)	-	-	84,043.19	-	-	261,621.79
Electric Hydro Production............................	(374,056.75)	(3,466.72)	-	-	-	-	29,260.00	-	-	(348,263.47)
Electric Other Production.............................	(3,174,464.89)	(597,423.49)	-	-	-	-	64,009.38	-	-	(3,707,879.00)
Electric Steam Production............................	(113,988,699.33)	(16,677,445.88)	-	282,823.63	-	-	1,970,313.92	-	-	(128,413,007.66)
Electric Transmission...................................	(137,175,896.62)	(1,862,026.32)	-	-	-	-	1,723,415.98	-	-	(137,314,506.96)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(450,323,661.31)	(24,548,197.66)	-	322,823.63	-	-	6,895,738.88	-	-	(467,653,296.46)
Salvage										
Electric Distribution.....................................	48,221,606.07	1,311,750.30	-	-	-	-	-	(201,602.41)	-	49,331,753.96
Electric General Plant..................................	149,758.57	-	-	-	-	-	-	-	-	149,758.57
Electric Hydro Production............................	46,518.69	-	-	-	-	-	-	-	-	46,518.69
Electric Other Production.............................	618,891.61	-	-	-	-	-	-	-	-	618,891.61
Electric Steam Production............................	20,938,580.66	3,067,273.19	-	-	-	-	-	(1,360,313.33)	-	22,645,540.52
Electric Transmission...................................	23,009,336.80	432,200.53	-	-	-	-	-	(13,024.97)	-	23,428,512.36
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	92,984,692.40	4,811,224.02	-	-	-	-	-	(1,574,940.71)	-	96,220,975.71
Total Reserves										
Electric Distribution.....................................	(546,288,517.18)	(22,443,435.61)	14,392,927.93	(144,871.59)	-	-	3,024,696.41	(201,602.41)	-	(551,660,802.45)
Electric Distribution - ARO..........................	(790.87)	(2,955.59)	-	-	-	-	-	-	-	(3,746.46)
Electric General Plant..................................	(57,364,463.48)	(4,059,682.72)	4,151,861.13	181,198.51	-	-	84,043.19	-	-	(57,007,043.37)
Electric Hydro Production............................	(8,092,615.71)	(83,038.61)	15,190.72	-	-	-	29,260.00	-	-	(8,131,203.60)
Electric Hydro Production - ARO................	(121.57)	(648.64)	-	-	-	-	-	-	-	(770.21)
Electric Other Production.............................	(162,968,393.88)	(11,746,531.76)	2,081,136.52	-	-	-	64,009.38	-	-	(172,569,779.74)
Electric Other Production - ARO.................	(84.76)	(452.56)	-	-	-	-	-	-	-	(537.32)
Electric Steam Production............................	(1,161,048,060.72)	(72,638,362.32)	10,322,312.10	-	-	-	1,970,313.92	(1,360,313.33)	-	(1,222,754,110.35)
Electric Steam Production - ARO................	(485,952.30)	(2,002,703.14)	56,694.92	-	-	-	-	-	-	(2,431,960.52)
Electric Transmission...................................	(325,528,090.93)	(7,596,871.35)	2,144,365.09	-	-	-	1,723,415.98	(13,024.97)	-	(329,270,206.18)
Electric Transmission - ARO.......................	(156.99)	(837.59)	-	-	-	-	-	-	-	(994.58)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(2,261,777,248.39)	(120,575,519.89)	33,164,488.41	36,326.92	-	-	6,895,738.88	(1,574,940.71)	-	(2,343,831,154.78)
Retirement Work in Process										
Electric...	13,605,672.01		-	14,675.52	(161,732.61)	(5,159,065.56)	8,221,398.22	(633,844.65)	(236,553.29)	15,650,549.64
	13,605,672.01	-	-	14,675.52	(161,732.61)	(5,159,065.56)	8,221,398.22	(633,844.65)	(236,553.29)	15,650,549.64
YTD ACTIVITY	(2,248,171,576.38)	(120,575,519.89)	33,164,488.41	51,002.44	(161,732.61)	(5,159,065.56)	15,117,137.10	(2,208,785.36)	(236,553.29)	(2,328,180,605.14)
Amortization										
Electric...	(13,755,205.98)	(4,712,034.88)	1,381,084.50	-	-	-	-	-	-	(17,086,156.36)
	(13,755,205.98)	(4,712,034.88)	1,381,084.50	-	-	-	-	-	-	(17,086,156.36)
Depreciation & Amortization Total										
Depreciation & Amortization Total...............	(2,261,926,782.36)	(125,287,554.77)	34,545,572.91	51,002.44	(161,732.61)	(5,159,065.56)	15,117,137.10	(2,208,785.36)	(236,553.29)	(2,345,266,761.50)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)..............	$ 4,234,854,513.03									$ 4,272,161,522.88

September 22, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of August 31, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 148,489,668.83	$ -	$ 148,489,668.83
Rate Refunds	-	-	-
Total Operating Revenues	148,489,668.83	-	148,489,668.83
Fuel for Electric Generation	53,286,923.89	-	53,286,923.89
Power Purchased	7,736,351.66	-	7,736,351.66
Other Operation Expenses	21,859,470.84	-	21,859,470.84
Maintenance	9,348,475.54	-	9,348,475.54
Depreciation	15,286,992.02	-	15,286,992.02
Amortization Expense	607,618.79	-	607,618.79
Regulatory Credits	(474,471.65)	-	(474,471.65)
Taxes			
Federal Income	10,712,248.19	-	10,712,248.19
State Income	1,953,601.50	-	1,953,601.50
Deferred Federal Income - Net	-	(22,475.59)	(22,475.59)
Deferred State Income - Net	-	(4,098.89)	(4,098.89)
Property and Other	2,221,248.95	-	2,221,248.95
Loss (Gain) from Disposition of Allowances	-	-	-
Accretion Expense	230,559.05	-	230,559.05
Total Operating Expenses	122,769,018.78	(26,574.48)	122,742,444.30
Net Operating Income	25,720,650.05	26,574.48	25,747,224.53
Other Income Less Deductions			
Amortization of Investment Tax Credit	233,343.00	-	233,343.00
Other Income Less Deductions	421,793.54	(73,840.35)	347,953.19
AFUDC - Equity	4,596.47	-	4,596.47
Total Other Income Less Deductions	659,733.01	(73,840.35)	585,892.66
Income Before Interest Charges	26,380,383.06	(47,265.87)	26,333,117.19
Interest on Long-Term Debt	5,093,452.69	(5,525.49)	5,087,927.20
Amortization of Debt Expense - Net	324,095.50	-	324,095.50
Other Interest Expenses	410,154.45	-	410,154.45
AFUDC - Borrowed Funds	(1,394.81)	-	(1,394.81)
Total Interest Charges	5,826,307.83	(5,525.49)	5,820,782.34
Net Income	$ 20,554,075.23	$ (41,740.38)	$ 20,512,334.85

Note: Purchase accounting is subject to change through October 31, 2011

September 22, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of August 31, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues...................................	$ 1,072,448,087.73	$ -	$ 1,072,448,087.73
Rate Refunds...	-	-	-
Total Operating Revenues....................................	1,072,448,087.73	-	1,072,448,087.73
Fuel for Electric Generation.....................................	368,637,714.79	-	368,637,714.79
Power Purchased...	72,690,645.43	-	72,690,645.43
Other Operation Expenses.......................................	156,114,344.96	31,612.30	156,145,957.26
Maintenance..	81,235,094.04	-	81,235,094.04
Depreciation..	120,425,868.85	-	120,425,868.85
Amortization Expense...	4,712,034.88	-	4,712,034.88
Regulatory Credits...	(3,829,873.90)	-	(3,829,873.90)
Taxes			
Federal Income..	19,302,498.06	-	19,302,498.06
State Income..	8,609,098.50	-	8,609,098.50
Deferred Federal Income - Net..............................	48,680,498.78	(44,444.29)	48,636,054.49
Deferred State Income - Net..................................	2,692,792.20	(8,105.34)	2,684,686.86
Property and Other..	18,377,778.99	-	18,377,778.99
Loss (Gain) from Disposition of Allowances...........	(3,293.39)	-	(3,293.39)
Accretion Expense...	1,822,276.38	-	1,822,276.38
Total Operating Expenses.....................................	899,467,478.57	(20,937.33)	899,446,541.24
Net Operating Income...	172,980,609.16	20,937.33	173,001,546.49
Other Income Less Deductions			
Amortization of Investment Tax Credit.............	1,753,033.00	-	1,753,033.00
Other Income Less Deductions..........................	1,351,432.13	849,100.46	2,200,532.59
AFUDC - Equity...	22,773.61	-	22,773.61
Total Other Income Less Deductions....................	3,127,238.74	849,100.46	3,976,339.20
Income Before Interest Charges............................	176,107,847.90	870,037.79	176,977,885.69
Interest on Long-Term Debt....................................	40,904,449.71	(44,203.93)	40,860,245.78
Amortization of Debt Expense - Net........................	2,451,219.70	-	2,451,219.70
Other Interest Expenses...	3,758,112.24	-	3,758,112.24
AFUDC - Borrowed Funds......................................	(6,920.56)	-	(6,920.56)
Total Interest Charges...	47,106,861.09	(44,203.93)	47,062,657.16
Net Income..	$ 129,000,986.81	$ 914,241.72	$ 129,915,228.53

Note: Purchase accounting is subject to change through October 31, 2011

September 22, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of August 31, 2011

Retained Earnings and Undistributed Earnings	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,478,281,685.40	$ 15,949,215.75	$ (1,402,527,187.23)	$ (14,905,382.89)	$ 75,754,498.17	$ 1,043,832.86
Add						
Net Income for Period..	20,554,075.23	-	(41,740.38)	-	20,512,334.85	-
Deductions:						
Common Dividends						
Common Stock Without Par Value..................	(19,500,000.00)	-	-	-	(19,500,000.00)	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc...	(753,088.00)	753,088.00	73,840.35	(73,840.35)	(679,247.65)	679,247.65
Balance at End of Period	$ 1,478,582,672.63	$ 16,702,303.75	$ (1,402,495,087.26)	$ (14,979,223.24)	$ 76,087,585.37	$ 1,723,080.51
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings................		16,702,303.75		(14,979,223.24)		1,723,080.51
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.........................		$ 6,497,196.16		$ (5,826,917.84)		$ 670,278.32

Note: Purchase accounting is subject to change through October 31, 2011.

September 22, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of August 31, 2011

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,439,351,593.82	$ 14,432,395.75	$ (1,404,000,051.78)	$ (14,388,500.44)	$ 35,351,542.04	$ 43,895.31
Add						
Net Income for Period ………………………………	129,000,986.81	-	914,241.72	-	129,915,228.53	-
Deductions:						
Common Dividends						
Common Stock Without Par Value...................	(87,500,000.00)		-		(87,500,000.00)	
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc……………………….…………	(2,269,908.00)	2,269,908.00	590,722.80	(590,722.80)	(1,679,185.20)	1,679,185.20
Balance at End of Period …...……………………………	$ 1,478,582,672.63	$ 16,702,303.75	$ (1,402,495,087.26)	$ (14,979,223.24)	$ 76,087,585.37	$ 1,723,080.51
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings…………		16,702,303.75		(14,979,223.24)		1,723,080.51
Statutory Tax Rate…...…………………………………		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary…...………………		$ 6,497,196.16		$ (5,826,917.84)		$ 670,278.32

Note: Purchase accounting is subject to change through October 31, 2011

September 22, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of August 31, 2011

Retained Earnings and Undistributed Earnings	Year Ended Current Month without Purchase Accounting: Retained Earnings	Year Ended Current Month without Purchase Accounting: Undistributed Subsidiary Earnings	Year Ended Current Month to Date Purchase Accounting: Retained Earnings	Year Ended Current Month to Date Purchase Accounting: Undistributed Subsidiary Earnings	Year Ended Current Month Combined: Retained Earnings	Year Ended Current Month Combined: Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,429,565,807.71	$ 14,553,781.75			$ 1,429,565,807.71	$ 14,553,781.75
Add						
Net Income for Period...	188,665,386.92	-	850,076.10	-	189,515,463.02	-
Purchase Accounting Deductions:			(1,404,083,566.85)	(14,240,819.75)	(1,404,083,566.85)	(14,240,819.75)
Deductions:						
Common Dividends						
Common Stock Without Par Value...................	(137,500,000.00)		-		(137,500,000.00)	
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	(2,148,522.00)	2,148,522.00	738,403.49	(738,403.49)	(1,410,118.51)	1,410,118.51
Balance at End of Period	$ 1,478,582,672.63	$ 16,702,303.75	$ (1,402,495,087.26)	$ (14,979,223.24)	$ 76,087,585.37	$ 1,723,080.51

Deferred Taxes Related to Undistributed Subsidiary Earnings	Without Purchase Accounting	To Date Purchase Accounting	Combined
Balance of Undistributed Subsidiary Earnings................	16,702,303.75	(14,979,223.24)	1,723,080.51
Statutory Tax Rate...	38.9%	38.9%	38.9%
Deferred Taxes on Equity in Subsidiary..........................	$ 6,497,196.16	$ (5,826,917.84)	$ 670,278.32

Combined Balance of Retained Earnings	12 MONTHS 8/31/2011	12 MONTHS 8/31/2010
Retained Earnings at Beginning of Period.......................	$ 1,444,119,589.46	$ 1,253,498,142.32
Net Income for Period	189,515,463.02	190,621,447.14
FIN 48 Adjustment...	-	-
Subtotal..	1,633,635,052.48	1,444,119,589.46
Deduct		
Purchase Accounting Adjustment...............................	1,418,324,386.60	
Dividends on Common Stock.....................................	137,500,000.00	-
Retained Earnings at End of Period.................................	$ 77,810,665.88	$ 1,444,119,589.46

Note: Purchase accounting is subject to change through October 31, 2011

September 22, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of August 31, 2011

Assets	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 6,617,428,284.38	$ -	$ 6,617,428,284.38
Less Reserves for Depreciation and Amortization.....	2,345,266,761.50	-	2,345,266,761.50
Total..	4,272,161,522.88	-	4,272,161,522.88
Investments			
Electric Energy, Inc...	13,946,037.55	16,983,279.51	30,929,317.06
Ohio Valley Electric Corporation.............................	250,000.00	-	250,000.00
Nonutility Property - Less Reserve...........................	179,120.94	-	179,120.94
Special Funds...	-	-	-
Total..	14,375,158.49	16,983,279.51	31,358,438.00
Current and Accrued Assets			
Cash..	38,149,431.99	-	38,149,431.99
Special Deposits..	256,665.50	-	256,665.50
Temporary Cash Investments.................................	49,715,396.92	-	49,715,396.92
Accounts Receivable-Less Reserve........................	186,539,676.89	-	186,539,676.89
Accounts Receivable from Assoc Companies..........	63,189.83	-	63,189.83
Materials & Supplies-At Average Cost			
Fuel..	74,480,640.86	-	74,480,640.86
Plant Materials & Operating Supplies..................	32,890,103.41	-	32,890,103.41
Stores Expense..	9,837,806.88	-	9,837,806.88
Allowance Inventory..	490,495.67	-	490,495.67
Prepayments..	8,071,702.33	-	8,071,702.33
Miscellaneous Current & Accrued Assets..............	161,940.18	-	161,940.18
Total..	400,657,050.46	-	400,657,050.46
Deferred Debits and Other			
Unamortized Debt Expense......................................	21,631,100.79	(4,481,976.31)	17,149,124.48
Unamortized Loss on Bonds....................................	11,976,774.93	-	11,976,774.93
Accumulated Deferred Income Taxes.......................	76,681,026.30	69,181,824.41	145,862,850.71
Deferred Regulatory Assets.....................................	283,333,140.25	15,278,263.27	298,611,403.52
Other Deferred Debits..	44,460,143.95	155,902,254.10	200,362,398.05
Goodwill..	-	607,404,368.23	607,404,368.23
Total..	438,082,186.22	843,284,733.70	1,281,366,919.92
Total Assets..	$ 5,125,275,918.05	$ 860,268,013.21	$ 5,985,543,931.26

Note: Purchase accounting is subject to change through October 31, 2011

September 22, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of August 31, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Proprietary Capital			
Common Stock..	$ 308,139,977.56	$ -	$ 308,139,977.56
Less: Common Stock Expense....................................	321,288.87	-	321,288.87
Paid-In Capital...	315,858,083.00	2,032,588,750.94	2,348,446,833.94
Other Comprehensive Income.....................................	(2,467,297.63)	1,990,823.26	(476,474.37)
Retained Earnings...	1,478,582,672.63	(1,402,495,087.26)	76,087,585.37
Unappropriated Undistributed Subsidiary Earnings....	16,702,303.75	(14,979,223.24)	1,723,080.51
Total Proprietary Capital...	2,116,494,450.44	617,105,263.70	2,733,599,714.14
Pollution Control Bonds - Net of Reacquired Bonds...	350,779,405.00	1,106,200.09	351,885,605.09
First Mortgage Bonds..	1,489,600,406.25	-	1,489,600,406.25
Total Long-Term Debt...	1,840,379,811.25	1,106,200.09	1,841,486,011.34
Total Capitalization..	3,956,874,261.69	618,211,463.79	4,575,085,725.48
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Accounts Payable...	78,525,380.23	-	78,525,380.23
Accounts Payable to Associated Companies................	34,247,202.13	-	34,247,202.13
Customer Deposits...	23,264,959.01	-	23,264,959.01
Taxes Accrued..	41,215,179.56	-	41,215,179.56
Interest Accrued...	20,293,199.13	-	20,293,199.13
Dividends Declared..	19,500,000.00	-	19,500,000.00
Miscellaneous Current and Accrued Liabilities...........	19,827,702.88	-	19,827,702.88
Total..	236,873,622.94	-	236,873,622.94
Deferred Credits and Other			
Accumulated Deferred Income Taxes..........................	491,559,670.98	75,358,008.36	566,917,679.34
Investment Tax Credit..	102,341,136.32	-	102,341,136.32
Regulatory Liabilities...	115,465,105.22	155,902,254.10	271,367,359.32
Customer Advances for Construction..........................	3,240,757.14	-	3,240,757.14
Asset Retirement Obligations......................................	55,625,808.75	-	55,625,808.75
Other Deferred Credits...	26,164,116.81	10,796,286.96	36,960,403.77
Miscellaneous Long-Term Liabilities..........................	2,805,389.46	-	2,805,389.46
Accum Provision for Postretirement Benefits.............	134,326,048.74	-	134,326,048.74
Total..	931,528,033.42	242,056,549.42	1,173,584,582.84
Total Liabilities and Stockholders' Equity.........................	$ 5,125,275,918.05	$ 860,268,013.21	$ 5,985,543,931.26

Note: Purchase accounting is subject to change through October 31, 2011

September 22, 2011

KENTUCKY UTILITIES COMPANY

Financial Reports

July 31, 2011

Index
Financial and Operating Reports

Kentucky Utilities Company
July 31, 2011

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2011 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows, unless otherwise noted.

Kentucky Utilities Company
Comparative Statement of Income
July 31, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 152,725,550.31	$ 142,670,422.02	$ 10,055,128.29	7.05
Rate Refunds	-	-	-	-
Total Operating Revenues	152,725,550.31	142,670,422.02	10,055,128.29	7.05
Fuel for Electric Generation	57,931,087.86	53,730,406.62	4,200,681.24	7.82
Power Purchased	7,260,166.00	10,888,148.96	(3,627,982.96)	(33.32)
Other Operation Expenses	19,333,773.67	18,818,894.78	514,878.89	2.74
Maintenance	8,622,899.07	7,380,333.70	1,242,565.37	16.84
Depreciation	15,401,354.41	12,020,047.90	3,381,306.51	28.13
Amortization Expense	605,605.22	542,346.73	63,258.49	11.66
Regulatory Credits	(504,995.20)	(210,918.75)	(294,076.45)	(139.43)
Taxes				
Federal Income	11,764,783.74	10,218,079.77	1,546,703.97	15.14
State Income	2,145,553.27	1,863,479.60	282,073.67	15.14
Deferred Federal Income - Net	-	10.98	(10.98)	(100.00)
Deferred State Income - Net	-	-	-	-
Property and Other	2,266,031.26	1,656,124.32	609,906.94	36.83
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	-	-	-	-
Accretion Expense	230,133.65	186,173.78	43,959.87	23.61
Total Operating Expenses	125,056,392.95	117,093,128.39	7,963,264.56	6.80
Net Operating Income	27,669,157.36	25,577,293.63	2,091,863.73	8.18
Other Income Less Deductions				
Amortization of Investment Tax Credit	233,343.00	5,925.00	227,418.00	3,838.28
Other Income Less Deductions	235,429.03	347,729.61	(112,300.58)	(32.30)
AFUDC - Equity	4,031.76	94,699.19	(90,667.43)	(95.74)
Total Other Income Less Deductions	472,803.79	448,353.80	24,449.99	5.45
Income Before Interest Charges	28,141,961.15	26,025,647.43	2,116,313.72	8.13
Interest on Long-Term Debt	5,072,104.60	6,349,608.41	(1,277,503.81)	(20.12)
Amortization of Debt Expense - Net	324,095.50	68,470.36	255,625.14	373.34
Other Interest Expenses	425,131.56	265,434.91	159,696.65	60.16
AFUDC - Borrowed Funds	(1,225.42)	(82,809.92)	81,584.50	98.52
Total Interest Charges	5,820,106.24	6,600,703.76	(780,597.52)	(11.83)
Net Income	$ 22,321,854.91	$ 19,424,943.67	$ 2,896,911.24	14.91

August 19, 2011

Kentucky Utilities Company
Comparative Statement of Income
July 31, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues.....................................	$ 923,958,418.90	$ 873,213,421.49	$ 50,744,997.41	5.81
Rate Refunds...	-	(632,390.04)	632,390.04	100.00
Total Operating Revenues......................................	923,958,418.90	872,581,031.45	51,377,387.45	5.89
Fuel for Electric Generation......................................	315,350,790.90	298,459,149.93	16,891,640.97	5.66
Power Purchased...	64,954,293.77	105,145,273.36	(40,190,979.59)	(38.22)
Other Operation Expenses..	134,254,874.12	124,529,127.58	9,725,746.54	7.81
Maintenance..	71,886,618.50	56,791,619.20	15,094,999.30	26.58
Depreciation..	105,138,876.83	77,379,535.13	27,759,341.70	35.87
Amortization Expense...	4,104,416.09	3,854,650.86	249,765.23	6.48
Regulatory Credits..	(3,355,402.25)	(1,456,329.95)	(1,899,072.30)	(130.40)
Taxes				
Federal Income...	8,590,249.87	23,944,250.20	(15,354,000.33)	(64.12)
State Income...	6,655,497.00	3,403,658.30	3,251,838.70	95.54
Deferred Federal Income - Net...............................	48,680,498.78	23,499,276.36	25,181,222.42	107.16
Deferred State Income - Net...................................	2,692,792.20	5,096,830.24	(2,404,038.04)	(47.17)
Property and Other...	16,156,530.04	11,710,960.21	4,445,569.83	37.96
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances...........	(3,293.39)	(44,023.81)	40,730.42	92.52
Accretion Expense..	1,591,717.33	1,283,001.57	308,715.76	24.06
Total Operating Expenses......................................	776,698,459.79	733,596,979.18	43,101,480.61	5.88
Net Operating Income...	147,259,959.11	138,984,052.27	8,275,906.84	5.95
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	1,519,690.00	41,475.00	1,478,215.00	3,564.11
Other Income Less Deductions...........................	929,638.59	1,258,404.03	(328,765.44)	(26.13)
AFUDC - Equity...	18,177.14	(971.96)	19,149.10	1,970.15
Total Other Income Less Deductions......................	2,467,505.73	1,298,907.07	1,168,598.66	89.97
Income Before Interest Charges.............................	149,727,464.84	140,282,959.34	9,444,505.50	6.73
Interest on Long-Term Debt......................................	35,810,997.02	44,531,070.37	(8,720,073.35)	(19.58)
Amortization of Debt Expense - Net.........................	2,127,124.20	478,919.60	1,648,204.60	344.15
Other Interest Expenses..	3,347,957.79	2,043,768.60	1,304,189.19	63.81
AFUDC - Borrowed Funds.......................................	(5,525.75)	(554,652.52)	549,126.77	99.00
Total Interest Charges..	41,280,553.26	46,499,106.05	(5,218,552.79)	(11.22)
Net Income..	$ 108,446,911.58	$ 93,783,853.29	$ 14,663,058.29	15.63

August 19, 2011

Kentucky Utilities Company
Comparative Statement of Income
July 31, 2011

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues.....................................	$ 1,563,087,093.33	$ 1,438,915,877.33	$ 124,171,216.00	8.63
Rate Refunds..	6.12	(1,101,620.83)	1,101,626.95	100.00
Total Operating Revenues......................................	1,563,087,099.45	1,437,814,256.50	125,272,842.95	8.71
Fuel for Electric Generation......................................	512,975,829.10	479,651,229.76	33,324,599.34	6.95
Power Purchased...	134,430,957.68	181,173,909.86	(46,742,952.18)	(25.80)
Other Operation Expenses..	226,372,974.31	207,626,015.76	18,746,958.55	9.03
Maintenance..	122,908,984.10	49,828,319.40	73,080,664.70	146.66
Depreciation..	167,041,382.39	130,957,308.04	36,084,074.35	27.55
Amortization Expense...	6,853,229.15	6,623,175.14	230,054.01	3.47
Regulatory Credits..	(7,048,629.65)	(2,474,023.56)	(4,574,606.09)	(184.91)
Taxes				
Federal Income...	46,305,448.95	19,718,833.55	26,586,615.40	134.83
State Income...	16,008,231.21	2,774,074.99	13,234,156.22	477.07
Deferred Federal Income - Net...............................	47,456,674.17	59,959,085.46	(12,502,411.29)	(20.85)
Deferred State Income - Net...................................	907,000.14	12,683,650.17	(11,776,650.03)	(92.85)
Property and Other...	24,339,048.80	18,847,936.27	5,491,112.53	29.13
Investment Tax Credit..	-	10,708,227.54	(10,708,227.54)	(100.00)
Loss (Gain) from Disposition of Allowances...........	(16,020.32)	(44,023.81)	28,003.49	63.61
Accretion Expense..	3,807,620.70	2,174,188.39	1,633,432.31	75.13
Total Operating Expenses......................................	1,302,342,730.73	1,180,207,906.96	122,134,823.77	10.35
Net Operating Income...	260,744,368.72	257,606,349.54	3,138,019.18	1.22
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	1,549,315.00	103,397.50	1,445,917.50	1,398.41
Other Income Less Deductions...........................	729,148.48	(1,258,363.47)	1,987,511.95	157.94
AFUDC - Equity...	540,301.14	1,073,043.73	(532,742.59)	(49.65)
Total Other Income Less Deductions.....................	2,818,764.62	(81,922.24)	2,900,686.86	3,540.78
Income Before Interest Charges.............................	263,563,133.34	257,524,427.30	6,038,706.04	2.34
Interest on Long-Term Debt......................................	65,724,368.87	75,535,365.69	(9,810,996.82)	(12.99)
Amortization of Debt Expense - Net.........................	2,837,146.51	820,770.87	2,016,375.64	245.67
Other Interest Expenses..	5,263,612.16	3,413,770.80	1,849,841.36	54.19
AFUDC - Borrowed Funds.......................................	(419,470.16)	(1,012,146.46)	592,676.30	58.56
Total Interest Charges..	73,405,657.38	78,757,760.90	(5,352,103.52)	(6.80)
Net Income..	$ 190,157,475.96	$ 178,766,666.40	$ 11,390,809.56	6.37

August 19, 2011

Kentucky Utilities Company
Analysis of Retained Earnings
July 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
Retained Earnings and Undistributed Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period..	$ 1,456,456,761.49	$ 15,452,284.75	$ 1,439,351,593.82	$ 14,432,395.75	$ 1,408,559,586.44	$ 13,513,838.75
Add:						
Net Income for Period..	22,321,854.91	-	108,446,911.58	-	190,157,475.96	-
Deduct:						
Common Dividends						
Common Stock Without Par Value	-	-	(68,000,000.00)	-	(118,000,000.00)	-
EE Inc..	(496,931.00)	496,931.00	(1,516,820.00)	1,516,820.00	(2,435,377.00)	2,435,377.00
Balance at End of Period..	$ 1,478,281,685.40	$ 15,949,215.75	$ 1,478,281,685.40	$ 15,949,215.75	$ 1,478,281,685.40	$ 15,949,215.75

Deferred Taxes Related to Undistributed Subsidiary Earnings			
Balance of Undistributed Subsidiary Earnings.............................	15,949,215.75	15,949,215.75	15,949,215.75
Statutory Tax Rate...	38.9%	38.9%	38.9%
Deferred Taxes on Equity in Subsidiary.......................................	$ 6,204,244.93	$ 6,204,244.93	$ 6,204,244.93

August 19, 2011

Kentucky Utilities Company
Comparative Balance Sheets as of July 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,608,149,389.52	$ 6,292,996,294.30
Less: Reserves for Depreciation and Amortization	2,343,868,957.03	2,221,876,307.03
Total	4,264,280,432.49	4,071,119,987.27
Investments		
Electric Energy, Inc	13,185,620.55	14,809,638.75
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	179,120.94	179,120.94
Total	13,614,741.49	15,238,759.69
Current and Accrued Assets		
Cash	36,032,578.20	1,873,377.77
Special Deposits	405,895.98	-
Temporary Cash Investments	12,237.44	269.25
Accounts Receivable-Less Reserve	189,095,847.43	198,824,644.88
Accounts Receivable from Associated Companies	236,912.87	11,182,413.52
Materials and Supplies-At Average Cost		
Fuel	82,091,389.23	113,709,477.32
Plant Materials and Operating Supplies	32,983,715.02	32,300,668.18
Stores Expense	9,807,522.54	8,261,558.77
Emission Allowances	501,513.10	641,938.73
Prepayments	6,960,359.10	5,081,670.50
Miscellaneous Current and Accrued Assets	106,129.25	54,702.67
Total	358,234,100.16	371,930,721.59
Deferred Debits and Other		
Unamortized Debt Expense	21,851,844.40	4,716,703.92
Unamortized Loss on Bonds	12,027,189.32	12,632,162.00
Accumulated Deferred Income Taxes	76,681,026.30	46,858,854.08
Deferred Regulatory Assets	283,083,685.27	236,606,405.80
Other Deferred Debits	44,360,914.74	41,237,829.68
Total	438,004,660.03	342,051,955.48
Total Assets	$ 5,074,133,934.17	$ 4,800,341,424.03

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	315,858,083.00	315,858,083.00
Other Comprehensive Income	(2,474,626.63)	-
Retained Earnings	1,478,281,685.40	1,408,559,586.44
Unappropriated Undistributed Subsidiary Earnings	15,949,215.75	13,513,838.75
Total Proprietary Capital	2,115,433,046.21	2,045,750,196.88
Pollution Control Bonds	350,779,405.00	350,779,405.00
First Mortgage Bonds	1,489,547,468.75	-
LT Notes Payable to Associated Companies	-	1,298,000,000.00
Total Long-Term Debt	1,840,326,873.75	1,648,779,405.00
Total Capitalization	3,955,759,919.96	3,694,529,601.88
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	122,357,954.00
Accounts Payable	78,763,356.44	92,391,022.33
Accounts Payable to Associated Companies	23,378,743.34	51,400,483.88
Customer Deposits	23,337,255.65	22,376,904.10
Taxes Accrued	26,769,889.12	16,093,281.26
Interest Accrued	15,131,089.09	522,943.08
Miscellaneous Current and Accrued Liabilities	21,498,930.21	19,739,403.98
Total	188,879,263.85	324,881,992.63
Deferred Credits and Other		
Accumulated Deferred Income Taxes	491,559,670.98	409,153,631.96
Investment Tax Credit	102,574,479.32	104,123,794.32
Regulatory Liabilities	115,411,913.60	52,420,430.89
Customer Advances for Construction	3,162,568.61	3,047,140.99
Asset Retirement Obligations	55,395,249.70	35,633,472.98
Other Deferred Credits	24,253,215.69	24,438,427.68
Miscellaneous Long-Term Liabilities	2,805,389.46	2,660,205.61
Accum Provision for Postretirement Benefits	134,332,263.00	149,452,725.09
Total	929,494,750.36	780,929,829.52
Total Liabilities and Stockholders Equity	$ 5,074,133,934.17	$ 4,800,341,424.03

August 19, 2011

Kentucky Utilities Company
Statement of Capitalization and Short-Term Debt
July 31, 2011

	Authorized Shares	Issued and Outstanding Shares	Issued and Outstanding Amount	Percent of Total Capital
Proprietary Capital				
Common Stock - Without Par	80,000,000	37,817,878	$ 308,139,977.56	
Less: Common Stock Expense			321,288.87	
Paid-In Capital			315,858,083.00	
Other Comprehensive Income			(2,474,626.63)	
Retained Earnings			1,478,281,685.40	
Unappropriated Undistributed Subsidiary Earnings			15,949,215.75	
Total Proprietary Capital			2,115,433,046.21	53.47
Long-Term Debt				
Pollution Control Bonds				
Mercer County 2000 Series A due 05/01/23 Var%			12,900,000.00	
Carroll County 2002 Series A due 02/01/32 Var%			20,930,000.00	
Carroll County 2002 Series B due 02/01/32 Var%			2,400,000.00	
Carroll County 2002 Series C due 10/01/32 Var%			96,000,000.00	
Mercer County 2002 Series A due 02/01/32 Var%			7,400,000.00	
Muhlenburg County 2002 Series A due 02/01/32 Var%			2,400,000.00	
Carroll County 2004 Series A due 10/01/34 Var%			50,000,000.00	
Carroll County 2006 Series B due 10/01/34 Var%			54,000,000.00	
Carroll County 2007 Series A due 02/01/26 5.75%			17,875,000.00	
Trimble County 2007 Series A due 03/01/37 6.00%			8,927,000.00	
Carroll County 2008 Series A due 02/01/32 Var%			77,947,405.00	
Total Pollution Control Bonds			350,779,405.00	8.87
First Mortgage Bonds				
First Mortgage Bond due 11/01/15 1.625%			250,000,000.00	
First Mortgage Bond due 11/01/20 3.250%			500,000,000.00	
First Mortgage Bond due 11/01/40 5.125%			750,000,000.00	
Total First Mortgage Bonds			1,500,000,000.00	37.92
Less: First Mortgage Bonds Debt Discount				
First Mortgage Bond due 11/01/15 1.625%			(751,041.67)	
First Mortgage Bond due 11/01/20 3.250%			(1,756,125.00)	
First Mortgage Bond due 11/01/40 5.125%			(7,945,364.58)	
			(10,452,531.25)	(0.26)
Total First Mortgage Bonds - Net of Debt Discount			1,489,547,468.75	37.66
Total Capitalization			$ 3,955,759,919.96	100.00

August 19, 2011

Kentucky Utilities Company
Summary Trial Balance
July 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 6,608,149,389.52	$ 6,608,149,389.52
Reserves for Depreciation and Amortization		(2,343,868,957.03)
Depreciation of Plant	(2,327,390,419.46)	
Amortization of Plant	(16,478,537.57)	
Investments		13,614,741.49
Electric Energy, Inc	13,185,620.55	
Ohio Valley Electric Corporation	250,000.00	
Nonutility Property Reserve	179,120.94	
Cash	36,032,578.20	36,032,578.20
Special Deposits		405,895.98
MAN Margin Call	405,895.98	
Temporary Cash Investments	12,237.44	12,237.44
Accounts Receivable - Less Reserve		189,095,847.43
Unbilled Revenues	91,447,257.58	
Customers - Active	85,281,390.46	
Bechtel Liquidated Damages	6,310,710.00	
IMPA	2,256,583.99	
IMEA	2,125,267.62	
Transmission Sales	1,150,025.75	
Damage Claims	387,701.10	
IMEA/IMPA Net Portion of Bechtel Liquidated Damages	(1,577,677.50)	
Other	3,797,234.56	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	4,494,490.55	
Accrual	(3,516,465.27)	
Reserve	(2,087,112.00)	
Recoveries	(677,744.28)	
A/R Miscellaneous	(295,815.13)	
Accounts Receivable from Associated Companies		236,912.87
LG&E - KU Energy Services/Louisville Gas and Electric Company	236,912.87	
Fuel		82,091,389.23
Coal 1,326,631.38 Tons @ $56.07 MMBtu 30,561,921.34 @ 243.41¢	74,390,412.41	
Fuel Oil 3,031,499 Gallons @ 251.98¢	7,638,909.37	
Gas Pipeline 12,627.40 Mcf @ $4.92	62,067.45	
Plant Materials and Operating Supplies		32,983,715.02
Regular Materials and Supplies	32,420,618.28	
Limestone 52,202.60 Tons @ $10.79	563,096.72	
Other Reagents	0.02	
Stores Expense Undistributed	9,807,522.54	9,807,522.54

August 19, 2011

Kentucky Utilities Company
Summary Trial Balance
July 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Emission Allowances	$ 501,513.10	$ 501,513.10
Prepayments		6,960,359.10
Insurance	3,888,232.95	
Taxes	1,849,241.41	
Lease	658,579.94	
Risk Management and Workers Compensation	75,000.00	
Vehicle License	67,183.46	
Other	422,121.34	
Miscellaneous Current Assets		106,129.25
Derivative Asset - Non-Hedging	106,129.25	
Unamortized Debt Expense		21,851,844.40
Carroll County 2002 Series A due 02/01/32 Var%	84,054.34	
Carroll County 2002 Series B due 02/01/32 Var%	58,419.62	
Carroll County 2002 Series C due 10/01/32 Var%	1,559,094.19	
Mercer County 2002 Series A due 02/01/32 Var%	23,463.40	
Muhlenburg County 2002 Series A due 02/01/32 Var%	65,032.11	
Carroll County 2006 Series B due 10/01/34 Var%	1,110,147.44	
Carroll County 2007 Series A due 02/01/26 5.75%	483,460.80	
Trimble County 2007 Series A due 03/01/37 6.00%	411,167.09	
Carroll County 2008 Series A due 02/01/32 Var%	705,193.29	
First Mortgage Bond due 11/01/15 1.625%	1,931,118.81	
First Mortgage Bond due 11/01/20 3.250%	3,842,417.31	
First Mortgage Bond due 11/01/40 5.125%	7,270,235.81	
Revolving Credit Agreement	4,308,040.19	
Unamortized Loss on Bonds		12,027,189.32
Refinanced and Called Bonds	12,027,189.32	
Accumulated Deferred Income Taxes		76,681,026.30
Federal	64,935,848.93	
State	11,745,177.37	
Regulatory Assets		283,083,685.27
Pension and Postretirement Benefits	117,274,368.11	
SFAS 109 - Deferred Taxes	77,275,037.46	
2009 Winter Storm	51,513,082.66	
Fuel Adjustment Clause	6,057,000.00	
Virginia Mountain Snowstorm	6,041,670.12	
FERC Jurisdictional Pension Expense	5,444,744.42	
VA Fuel Component Non-Current	4,991,000.00	
Asset Retirement Obligations	4,728,476.91	
MISO Exit Fee	4,285,051.90	
2008 Wind Storm	1,975,964.71	
Rate Case Expenses	1,611,704.99	
EKPC FERC Transmission Cost	864,634.08	
KCCS Funding	691,470.38	
CMRG Funding	204,879.96	
General Management Audit	124,599.57	
Other Deferred Debits	44,360,914.74	44,360,914.74
Total Assets	$ 5,074,133,934.17	$ 5,074,133,934.17

August 19, 2011

Kentucky Utilities Company
Summary Trial Balance
July 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 2,115,433,046.21
Common Stock	308,139,977.56	
Less: Common Stock Expense	321,288.87	
Paid-In Capital	315,858,083.00	
Other Comprehensive Income	(2,474,626.63)	
Retained Earnings	1,478,281,685.40	
Unappropriated Undistributed Subsidiary Earnings	15,949,215.75	
Bonds		1,840,326,873.75
Pollution Control Bonds - Net of Reacquired Bonds	350,779,405.00	
First Mortgage Bonds	1,489,547,468.75	
Accounts Payable		78,763,356.44
Regular	75,882,942.14	
Salaries and Wages Accrued	2,874,909.41	
Employee Withholdings Payable	5,504.89	
Accounts Payable to Associated Companies		23,378,743.34
LG&E - KU Energy Services/Louisville Gas and Electric Company	23,378,743.34	
Customers' Deposits	23,337,255.65	23,337,255.65
Taxes Accrued	26,769,889.12	26,769,889.12
Interest Accrued		15,131,089.09
Mercer County 2000 Series A due 05/01/23 Var%	911.84	
Carroll County 2002 Series A due 02/01/32 Var%	7,225.16	
Carroll County 2002 Series B due 02/01/32 Var%	361.64	
Carroll County 2002 Series C due 10/01/32 Var%	2,666.67	
Mercer County 2002 Series A due 02/01/32 Var%	1,115.07	
Muhlenburg County 2002 Series A due 02/01/32 Var%	361.64	
Carroll County 2004 Series A due 10/01/34 Var%	3,438.35	
Carroll County 2006 Series B due 10/01/34 Var%	3,890.96	
Carroll County 2007 Series A due 02/01/26 5.75%	171,302.08	
Trimble County 2007 Series A due 03/01/37 6.00%	89,270.00	
Carroll County 2008 Series A due 02/01/32 Var%	5,595.13	
First Mortgage Bond due 11/01/15 1.625%	1,015,625.01	
First Mortgage Bond due 11/01/20 3.250%	4,062,500.00	
First Mortgage Bond due 11/01/40 5.125%	9,609,375.00	
Customers' Deposits	130,123.38	
Other	27,327.16	

August 19, 2011

Kentucky Utilities Company
Summary Trial Balance
July 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Miscellaneous Current and Accrued Liabilities		$ 21,498,930.21
Vacation Pay Accrued	6,700,744.77	
Franchise Fee Payable	6,655,553.36	
Tax Collections Payable	4,394,424.09	
Customer Overpayments	3,077,537.86	
Derivative Liabilities - Non-Hedging	311,865.58	
Home Energy Assistance	298,850.54	
Escheated Deposits	(200.91)	
Other	60,154.92	
Accumulated Deferred Income Taxes		491,559,670.98
Federal	427,861,146.32	
State	63,698,524.66	
Investment Tax Credit		102,574,479.32
Advanced Coal Credit	99,771,783.00	
Job Development Credit	2,802,696.32	
Regulatory Liabilities		115,411,913.60
Deferred Taxes		
Federal	62,438,640.72	
State	19,612,490.70	
Environmental Cost Recovery	11,150,003.15	
Postretirement Benefits	9,787,090.00	
DSM Cost Recovery	5,094,515.08	
Asset Retirement Obligations	4,522,343.51	
Spare Parts	1,906,297.00	
MISO Schedule 10 Charges	900,533.44	
Customers' Advances for Construction		3,162,568.61
Line Extensions	2,341,652.43	
Other	820,916.18	
Asset Retirement Obligations	55,395,249.70	55,395,249.70
Other Deferred Credits	24,253,215.69	24,253,215.69
Miscellaneous Long-Term Liabilities		2,805,389.46
Workers' Compensation	2,805,389.46	
Accumulated Provision for Benefits		134,332,263.00
Pension Payable	70,301,999.50	
Postretirement Benefits - SFAS 106	64,579,352.85	
Post Employment Benefits Payable	5,554,516.00	
Post Employment Medicare Subsidy	(382,793.62)	
Medicare Subsidy - SFAS 106	(5,720,811.73)	
Total Liabilities and Stockholders Equity	$ 5,074,133,934.17	$ 5,074,133,934.17

August 19, 2011

Kentucky Utilities Company
Statement of Cash Flows
July 31, 2011

	Year to Date 2011	Year to Date 2010
Cash Flows from Operating Activities		
Net income	$ 108,446,911.58	$ 93,783,853.29
Items not requiring (providing) cash currently:		
Depreciation	105,138,876.83	77,379,535.13
Amortization	4,104,416.09	3,854,650.86
Deferred income taxes - net	52,824,001.11	28,596,106.60
Investment Tax Credit	(1,561,163.00)	-
Gain on disposal of assets	(32,935.79)	(13,059.44)
Other	(5,504,846.60)	12,925,072.21
Change in receivables	2,605,372.75	(27,858,850.31)
Change in inventory	12,112,415.19	(18,576,991.05)
Change in allowance inventory	65,065.90	333,137.17
Change in payables and accrued expenses	(4,798,900.14)	(22,804,737.87)
Change in regulatory assets	(66,552,638.12)	17,065,343.25
Change in regulatory liabilities	60,262,276.74	8,175,987.49
Change in other deferred debits	(15,503,297.63)	(692,981.29)
Change in other deferred credits	15,889,487.20	14,570,980.58
Pension and postretirement funding	(46,279,600.00)	(16,795,900.00)
Other	11,711,899.96	(273,214.23)
Less: Allowance for other funds used during construction	(12,651.39)	(553,680.56)
Less: Undistributed earnings of subsidiary company	(1,516,820.00)	(2,842,470.00)
Net cash provided (used) by operating activities	231,397,870.68	166,272,781.83
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(112,100,846.65)	(211,026,941.95)
Less: Allowance for other funds used during construction	12,651.39	553,680.56
Proceeds received from sales of property	45,055.68	-
Change in derivatives	-	19,284.05
Change in restricted cash	-	-
Other	(6,167,383.32)	-
Net cash provided (used) by investing activities	(118,210,522.90)	(210,453,977.34)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(2,041,979.00)	(514.80)
Net change in short-term debt	(10,434,000.00)	44,383,000.00
Dividends on common stock	(68,000,000.00)	-
Net cash provided (used) by financing activities	(80,475,979.00)	44,382,485.20
Net Increase (Decrease) in Cash and Cash Equivalents	32,711,368.78	201,289.69
Cash and Cash Equivalents at Beginning of Period	3,333,446.86	1,672,357.33
Cash and Cash Equivalents at End of Period	$ 36,044,815.64	$ 1,873,647.02

August 19, 2011

Kentucky Utilities Company
Analysis of Interest Charges
July 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Interest on Long-Term Debt						
Loan Agreement - Pollution Control Bonds						
Mercer County 2000 Series A due 05/01/23 Var%..............	$ 911.84	$ 3,824.05	$ 15,843.62	$ 23,039.67	$ 35,013.38	$ 45,637.65
Carroll County 2002 Series A due 02/01/32 Var%..............	10,952.42	11,468.50	123,337.94	88,450.78	183,318.16	184,671.43
Carroll County 2002 Series B due 02/01/32 Var%..............	1,190.13	1,315.07	13,957.34	10,142.47	20,835.14	21,175.89
Carroll County 2002 Series C due 10/01/32 Var%..............	15,146.67	53,114.67	166,997.43	461,863.96	392,933.43	574,599.95
Mercer County 2002 Series A due 02/01/32 Var%..............	3,669.59	4,054.80	41,855.63	31,272.62	63,062.20	65,292.35
Muhlenburg County 2002 Series A due 02/01/32 Var%.......	1,190.13	1,315.07	13,574.83	10,142.47	20,452.63	21,175.89
Carroll County 2004 Series A due 10/01/34 Var%..............	3,438.36	13,136.99	68,958.80	84,438.36	134,821.81	155,000.01
Carroll County 2006 Series B due 10/01/34 Var%..............	3,890.96	14,143.56	75,940.27	95,853.71	146,554.51	186,736.46
Carroll County 2007 Series A due 02/01/26 5.75%.............	85,651.04	85,651.04	599,557.29	599,557.29	1,027,812.50	1,027,812.50
Trimble County 2007 Series A due 03/01/37 6.00%............	44,635.00	44,635.00	312,445.00	312,445.00	535,620.00	535,620.00
Carroll County 2008 Series A due 02/01/32 Var%..............	5,595.13	20,437.17	107,695.54	138,276.55	209,646.47	269,458.84
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/01/15 1.625%.........................	338,541.67	-	2,369,791.67	-	2,877,604.18	-
First Mortgage Bond due 11/01/20 3.250%.........................	1,354,166.66	-	9,479,166.66	-	11,510,416.67	-
First Mortgage Bond due 11/01/40 5.125%.........................	3,203,125.00	-	22,421,875.00	-	27,226,562.50	-
Fidelia/PPL..	-	6,096,512.49	-	42,675,587.49	21,339,715.29	72,448,184.72
Total..	5,072,104.60	6,349,608.41	35,810,997.02	44,531,070.37	65,724,368.87	75,535,365.69
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense..................................	273,681.11	18,055.97	1,774,223.47	126,174.05	2,232,173.83	216,158.77
Amortization of Loss on Reacquired Debt...............................	50,414.39	50,414.39	352,900.73	352,745.55	604,972.68	604,612.10
Total..	324,095.50	68,470.36	2,127,124.20	478,919.60	2,837,146.51	820,770.87
Other Interest Charges						
Customers' Deposits..	114,735.88	105,133.93	798,194.20	846,506.81	1,315,257.26	1,264,017.58
Other Tax Deficiencies..	-	-	-	1,139.07	86,502.00	1,139.07
Interest on DSM Cost Recovery...	1,465.48	(795.21)	5,098.01	9,749.08	13,729.62	61,522.62
Interest on Debt to Associated Companies..............................	474.59	22,370.92	5,788.76	78,550.69	54,281.48	83,267.22
AFUDC Borrowed Funds..	(1,225.42)	(82,809.92)	(5,525.75)	(554,652.52)	(419,470.16)	(1,012,146.46)
Other Interest Expense..	308,455.61	138,725.27	2,538,876.82	1,107,822.95	3,793,841.80	2,003,824.31
Total..	423,906.14	182,624.99	3,342,432.04	1,489,116.08	4,844,142.00	2,401,624.34
Total Interest...	$ 5,820,106.24	$ 6,600,703.76	$ 41,280,553.26	$ 46,499,106.05	$ 73,405,657.38	$ 78,757,760.90

August 19, 2011

Kentucky Utilities Company
Analysis of Taxes Charged and Accrued
July 31, 2011

Kind of Taxes	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year
Taxes Charged to Accounts 408.1 and 409.1...........				
Property Taxes..	$ 1,494,264.00	$ 908,194.01	$ 10,464,479.77	$ 6,357,358.07
Unemployment..	3,286.17	4,002.38	85,903.40	88,715.83
FICA..	588,085.91	577,264.62	4,442,513.47	4,124,256.33
Public Service Commission Fee..............................	168,112.85	157,659.37	1,114,069.12	1,095,405.15
Federal Income..	11,764,783.74	10,218,079.77	8,590,249.87	23,944,250.20
State Income...	2,145,553.27	1,863,479.60	6,655,497.00	3,403,658.30
Miscellaneous...	12,282.33	9,003.94	49,564.28	45,224.83
Total Charged to Operating Expense..........	16,176,368.27	13,737,683.69	31,402,276.91	39,058,868.71
Taxes Charged to Other Accounts..........................	523,421.35	(14,686,939.03)	3,120,875.62	1,990,563.89
Taxes Accrued on Intercompany Accounts............	(32,034.02)	(229,393.57)	(2,184,660.11)	(1,806,369.16)
Total Taxes Charged.................................	$ 16,667,755.60	$ (1,178,648.91)	$ 32,338,492.42	$ 39,243,063.44

Analysis of Taxes Accrued - Account 236

Kind of Taxes	Taxes Accrued At Beginning Of Year	Accruals To Date This Year	Payments To Date This Year	Taxes Accrued At End Of Month
Property Taxes..	$ 8,399,528.00	$ 10,465,648.77	$ 8,321,549.47	$ 10,543,627.30
Unemployment..	75,728.12	58,956.66	134,430.81	253.97
FICA..	639,011.24	3,613,356.06	3,735,538.49	516,828.81
Federal Income..	12,876,014.95	8,592,387.45	9,041,229.00	12,427,173.40
State Income...	2,021,178.48	7,106,769.83	6,250,451.00	2,877,497.31
Kentucky Sales and Use Tax..................................	581,659.33	2,390,390.39	2,578,975.46	393,074.26
Miscellaneous...	21,662.86	110,983.26	121,212.05	11,434.07
Totals...	$ 24,614,782.98	$ 32,338,492.42	$ 30,183,386.28	$ 26,769,889.12

August 19, 2011

Kentucky Utilities Company
Summary of Utility Plant
July 31, 2011

		Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101	**Utility Plant in Service**						
	Electric						
	Electric Distribution	$ 1,312,664,325.73	$ 37,343,996.23	$ (8,724,243.99)	$ 787,154.19	$ 29,406,906.43	$ 1,342,071,232.16
	Electric General Plant	125,243,994.19	10,506,309.06	(4,065,539.47)	(787,154.19)	5,653,615.40	130,897,609.59
	Electric Hydro Production	16,848,655.18	300,776.20	(15,190.72)	-	285,585.48	17,134,240.66
	Electric Intangible Plant	49,640,906.77	7,163,358.46	(1,381,084.50)	-	5,782,273.96	55,423,180.73
	Electric Other Production	519,412,128.33	2,764,320.78	(303,621.05)	-	2,460,699.73	521,872,828.06
	Electric Steam Production	1,814,421,935.78	724,506,668.16	(5,030,707.60)	120,828,152.53	840,304,113.09	2,654,726,048.87
	Electric Transmission	552,965,733.49	8,198,313.90	(1,421,360.56)	-	6,776,953.34	559,742,686.83
	Total 101 Accounts	4,391,197,679.47	790,783,742.79	(20,941,747.89)	120,828,152.53	890,670,147.43	5,281,867,826.90
102	**Electric Plant Purchased or Sold**						
	Electric						
	Electric Steam	483,341.17	-	-	-	-	483,341.17
	Total 102001	483,341.17	-	-	-	-	483,341.17
105	**Plant Held for Future Use**						
	Electric						
	Electric Distribution	792,599.21	-	-	-	-	792,599.21
	Electric Steam	120,828,152.53	-	-	(120,828,152.53)	(120,828,152.53)	-
	Total 105001	121,620,751.74	-	-	(120,828,152.53)	(120,828,152.53)	792,599.21
106	**Completed Construction Not Classified**						
	Electric						
	Electric Distribution	36,610,963.62	2,816,467.75	-	-	2,816,467.75	39,427,431.37
	Electric General Plant	769,342.30	1,493,546.60	-	-	1,493,546.60	2,262,888.90
	Electric Hydro Production	-	7,762.58	-	-	7,762.58	7,762.58
	Electric Intangible Plant	2,685,464.69	(1,652,822.23)	-	-	(1,652,822.23)	1,032,642.46
	Electric Other Production	3,737,695.33	(504,957.00)	-	-	(504,957.00)	3,232,738.33
	Electric Steam Production	910,748,505.16	(6,802,564.86)	-	-	(6,802,564.86)	903,945,940.30
	Electric Transmission	74,497,274.43	4,282,996.41	-	-	4,282,996.41	78,780,270.84
	Total 106 Accounts	1,029,049,245.53	(359,570.75)	-	-	(359,570.75)	1,028,689,674.78
121	**Nonutility Property**						
	Common						
	Non Utility Property	179,120.94	-	-	-	-	179,120.94
	Total 121001	179,120.94	-	-	-	-	179,120.94
107	**Construction Work In Progress**						
	Electric						
	Electric	954,430,277.48	(658,114,330.02)	-	-	(658,114,330.02)	296,315,947.46
	Total 107001	954,430,277.48	(658,114,330.02)	-	-	(658,114,330.02)	296,315,947.46
	Total Plant (Non-CWIP)	5,542,530,138.85	790,424,172.04	(20,941,747.89)	-	769,482,424.15	6,312,012,563.00
	Total Plant + CWIP	6,496,960,416.33	132,309,842.02	(20,941,747.89)	-	111,368,094.13	6,608,328,510.46
	Total Plant + CWIP - Nonutility (BS)	$ 6,496,781,295.39	$ 132,309,842.02	$ (20,941,747.89)	$ -	$ 111,368,094.13	$ 6,608,149,389.52

August 19, 2011

Kentucky Utilities Company
Summary of Utility Plant - Reserve for Depreciation of Utility Plant
July 31, 2011

	Beginning Balance	Accruals	Retirements	Transfers/ Adjustments	ARO Settlements	RWIP Transfers Out	Cost of Removal	Salvage	Other Credits	Ending Balance
Life Reserve										
Electric Distribution......................................	$ (398,692,068.83)	$ (16,052,458.27)	$ 8,724,243.99	$ (181,198.53)	$ -	$ -	$ -	$ -	$ -	$ (406,201,481.64)
Electric Distribution - ARO..........................	(790.87)	(2,586.15)	-	-	-	-	-	-	-	(3,377.02)
Electric General Plant..................................	(57,721,732.75)	(3,489,145.87)	4,065,539.47	181,198.53	-	-	-	-	-	(56,964,140.62)
Electric Hydro Production............................	(7,765,077.65)	(69,568.07)	15,190.72	-	-	-	-	-	-	(7,819,455.00)
Electric Hydro Production - ARO................	(121.57)	(567.56)	-	-	-	-	-	-	-	(689.13)
Electric Other Production.............................	(160,412,820.60)	(9,756,288.31)	303,621.05	-	-	-	-	-	-	(169,865,487.86)
Electric Other Production - ARO.................	(84.76)	(395.99)	-	-	-	-	-	-	-	(480.75)
Electric Steam Production............................	(1,067,997,942.05)	(51,522,337.74)	4,974,012.68	(282,823.63)	-	-	-	-	-	(1,114,829,090.74)
Electric Steam Production - ARO................	(485,952.30)	(1,759,402.32)	56,694.92	-	-	-	-	-	-	(2,188,659.70)
Electric Transmission...................................	(211,361,531.11)	(5,385,681.52)	1,421,360.56	-	-	-	-	-	-	(215,325,852.07)
Electric Transmission - ARO.......................	(156.99)	(732.90)	-	-	-	-	-	-	-	(889.89)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(1,904,438,279.48)	(88,039,164.70)	19,560,663.39	(282,823.63)	-	-	-	-	-	(1,973,199,604.42)
Cost of Removal										
Electric Distribution......................................	(195,818,054.42)	(4,695,921.97)	-	0.02	-	-	1,567,488.81	-	-	(198,946,487.56)
Electric General Plant..................................	207,510.70	(26,043.59)	-	(0.02)	-	-	63,950.74	-	-	245,417.83
Electric Hydro Production............................	(374,056.75)	(3,033.38)	-	-	-	-	29,260.00	-	-	(347,830.13)
Electric Other Production.............................	(3,174,464.89)	(522,803.08)	-	-	-	-	64,009.38	-	-	(3,633,258.59)
Electric Steam Production............................	(113,988,699.33)	(14,536,339.90)	-	282,823.63	-	-	1,726,074.98	-	-	(126,516,140.62)
Electric Transmission...................................	(137,175,896.62)	(1,625,870.05)	-	-	-	-	1,097,540.09	-	-	(137,704,226.58)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(450,323,661.31)	(21,410,011.97)	-	282,823.63	-	-	4,548,324.00	-	-	(466,902,525.65)
Salvage										
Electric Distribution......................................	48,221,606.07	1,145,288.03	-	-	-	-	-	(148,324.71)	-	49,218,569.39
Electric General Plant..................................	149,758.57	-	-	-	-	-	-	-	-	149,758.57
Electric Hydro Production............................	46,518.69	-	-	-	-	-	-	-	-	46,518.69
Electric Other Production.............................	618,891.61	-	-	-	-	-	-	-	-	618,891.61
Electric Steam Production............................	20,938,580.66	2,665,318.80	-	-	-	-	-	(1,175,831.90)	-	22,428,067.56
Electric Transmission...................................	23,009,336.80	377,459.56	-	-	-	-	-	(13,024.97)	-	23,373,771.39
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	92,984,692.40	4,188,066.39	-	-	-	-	-	(1,337,181.58)	-	95,835,577.21
Total Reserves										
Electric Distribution......................................	(546,288,517.18)	(19,603,092.21)	8,724,243.99	(181,198.51)	-	-	1,567,488.81	(148,324.71)	-	(555,929,399.81)
Electric Distribution - ARO..........................	(790.87)	(2,586.15)	-	-	-	-	-	-	-	(3,377.02)
Electric General Plant..................................	(57,364,463.48)	(3,515,189.46)	4,065,539.47	181,198.51	-	-	63,950.74	-	-	(56,568,964.22)
Electric Hydro Production............................	(8,092,615.71)	(72,601.45)	15,190.72	-	-	-	29,260.00	-	-	(8,120,766.44)
Electric Hydro Production - ARO................	(121.57)	(567.56)	-	-	-	-	-	-	-	(689.13)
Electric Other Production.............................	(162,968,393.88)	(10,279,091.39)	303,621.05	-	-	-	64,009.38	-	-	(172,879,854.84)
Electric Other Production - ARO.................	(84.76)	(395.99)	-	-	-	-	-	-	-	(480.75)
Electric Steam Production............................	(1,161,048,060.72)	(63,393,358.84)	4,974,012.68	-	-	-	1,726,074.98	(1,175,831.90)	-	(1,218,917,163.80)
Electric Steam Production - ARO................	(485,952.30)	(1,759,402.32)	56,694.92	-	-	-	-	-	-	(2,188,659.70)
Electric Transmission...................................	(325,528,090.93)	(6,634,092.01)	1,421,360.56	-	-	-	1,097,540.09	(13,024.97)	-	(329,656,307.26)
Electric Transmission - ARO.......................	(156.99)	(732.90)	-	-	-	-	-	-	-	(889.89)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(2,261,777,248.39)	(105,261,110.28)	19,560,663.39	-	-	-	4,548,324.00	(1,337,181.58)	-	(2,344,266,552.86)
Retirement Work in Process										
Electric..	13,605,672.01		-	14,675.52	(161,732.61)	(3,049,409.81)	7,294,073.48	(573,983.47)	(253,161.72)	16,876,133.40
	13,605,672.01	-	-	14,675.52	(161,732.61)	(3,049,409.81)	7,294,073.48	(573,983.47)	(253,161.72)	16,876,133.40
YTD ACTIVITY	(2,248,171,576.38)	(105,261,110.28)	19,560,663.39	14,675.52	(161,732.61)	(3,049,409.81)	11,842,397.48	(1,911,165.05)	(253,161.72)	(2,327,390,419.46)
Amortization										
Electric..	(13,755,205.98)	(4,104,416.09)	1,381,084.50	-	-	-	-	-	-	(16,478,537.57)
	(13,755,205.98)	(4,104,416.09)	1,381,084.50	-	-	-	-	-	-	(16,478,537.57)
Depreciation & Amortization Total										
Depreciation & Amortization Total...............	(2,261,926,782.36)	(109,365,526.37)	20,941,747.89	14,675.52	(161,732.61)	(3,049,409.81)	11,842,397.48	(1,911,165.05)	(253,161.72)	(2,343,868,957.03)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)..............	$ 4,234,854,513.03									$ 4,264,280,432.49

August 19, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of July 31, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues..................................	$ 152,725,550.31	$ -	$ 152,725,550.31
Rate Refunds..	-	-	-
Total Operating Revenues....................................	152,725,550.31	-	152,725,550.31
Fuel for Electric Generation....................................	57,931,087.86	-	57,931,087.86
Power Purchased..	7,260,166.00	-	7,260,166.00
Other Operation Expenses.......................................	19,333,773.67	-	19,333,773.67
Maintenance..	8,622,899.07	-	8,622,899.07
Depreciation..	15,401,354.41	-	15,401,354.41
Amortization Expense...	605,605.22	-	605,605.22
Regulatory Credits..	(504,995.20)	-	(504,995.20)
Taxes			
Federal Income..	11,764,783.74	-	11,764,783.74
State Income..	2,145,553.27	-	2,145,553.27
Deferred Federal Income - Net..............................	-	(22,475.59)	(22,475.59)
Deferred State Income - Net..................................	-	(4,098.89)	(4,098.89)
Property and Other..	2,266,031.26	-	2,266,031.26
Loss (Gain) from Disposition of Allowances...........	-	-	-
Accretion Expense..	230,133.65	-	230,133.65
Total Operating Expenses.....................................	125,056,392.95	(26,574.48)	125,029,818.47
Net Operating Income...	27,669,157.36	26,574.48	27,695,731.84
Other Income Less Deductions			
Amortization of Investment Tax Credit.............	233,343.00	-	233,343.00
Other Income Less Deductions..........................	235,429.03	(73,840.35)	161,588.68
AFUDC - Equity...	4,031.76	-	4,031.76
Total Other Income Less Deductions....................	472,803.79	(73,840.35)	398,963.44
Income Before Interest Charges............................	28,141,961.15	(47,265.87)	28,094,695.28
Interest on Long-Term Debt....................................	5,072,104.60	(5,525.49)	5,066,579.11
Amortization of Debt Expense - Net........................	324,095.50	-	324,095.50
Other Interest Expenses...	425,131.56	-	425,131.56
AFUDC - Borrowed Funds......................................	(1,225.42)	-	(1,225.42)
Total Interest Charges...	5,820,106.24	(5,525.49)	5,814,580.75
Net Income..	$ 22,321,854.91	$ (41,740.38)	$ 22,280,114.53

Note: Purchase accounting is subject to change through October 31, 2011

August 19, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of July 31, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues...................................	$ 923,958,418.90	$ -	$ 923,958,418.90
Rate Refunds...	-	-	-
Total Operating Revenues....................................	923,958,418.90	-	923,958,418.90
Fuel for Electric Generation.....................................	315,350,790.90	-	315,350,790.90
Power Purchased...	64,954,293.77	-	64,954,293.77
Other Operation Expenses.......................................	134,254,874.12	31,612.30	134,286,486.42
Maintenance..	71,886,618.50	-	71,886,618.50
Depreciation..	105,138,876.83	-	105,138,876.83
Amortization Expense...	4,104,416.09	-	4,104,416.09
Regulatory Credits...	(3,355,402.25)	-	(3,355,402.25)
Taxes			
Federal Income..	8,590,249.87	-	8,590,249.87
State Income..	6,655,497.00	-	6,655,497.00
Deferred Federal Income - Net..............................	48,680,498.78	(21,968.70)	48,658,530.08
Deferred State Income - Net..................................	2,692,792.20	(4,006.45)	2,688,785.75
Property and Other..	16,156,530.04	-	16,156,530.04
Loss (Gain) from Disposition of Allowances...........	(3,293.39)	-	(3,293.39)
Accretion Expense...	1,591,717.33	-	1,591,717.33
Total Operating Expenses.....................................	776,698,459.79	5,637.15	776,704,096.94
Net Operating Income...	147,259,959.11	(5,637.15)	147,254,321.96
Other Income Less Deductions			
Amortization of Investment Tax Credit.............	1,519,690.00	-	1,519,690.00
Other Income Less Deductions..........................	929,638.59	922,940.81	1,852,579.40
AFUDC - Equity...	18,177.14	-	18,177.14
Total Other Income Less Deductions....................	2,467,505.73	922,940.81	3,390,446.54
Income Before Interest Charges............................	149,727,464.84	917,303.66	150,644,768.50
Interest on Long-Term Debt....................................	35,810,997.02	(38,678.44)	35,772,318.58
Amortization of Debt Expense - Net........................	2,127,124.20	-	2,127,124.20
Other Interest Expenses...	3,347,957.79	-	3,347,957.79
AFUDC - Borrowed Funds......................................	(5,525.75)	-	(5,525.75)
Total Interest Charges...	41,280,553.26	(38,678.44)	41,241,874.82
Net Income..	$ 108,446,911.58	$ 955,982.10	$ 109,402,893.68

Note: Purchase accounting is subject to change through October 31, 2011

August 19, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of July 31, 2011

Retained Earnings and Undistributed Earnings	Current Month without Purchase Accounting: Retained Earnings	Current Month without Purchase Accounting: Undistributed Subsidiary Earnings	Current Month Purchase Accounting: Retained Earnings	Current Month Purchase Accounting: Undistributed Subsidiary Earnings	Current Month Combined: Retained Earnings	Current Month Combined: Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,456,456,761.49	$ 15,452,284.75	$ (1,402,559,287.20)	$ (14,831,542.54)	$ 53,897,474.29	$ 620,742.21
Add						
Net Income for Period..	22,321,854.91	-	(41,740.38)	-	22,280,114.53	-
Deductions:						
Common Dividends						
Common Stock Without Par Value..................	-	-	-	-	-	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	(496,931.00)	496,931.00	73,840.35	(73,840.35)	(423,090.65)	423,090.65
Balance at End of Period	$ 1,478,281,685.40	$ 15,949,215.75	$ (1,402,527,187.23)	$ (14,905,382.89)	$ 75,754,498.17	$ 1,043,832.86
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings................		15,949,215.75		(14,905,382.89)		1,043,832.86
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.........................		$ 6,204,244.93		$ (5,798,193.94)		$ 406,050.98

Note: Purchase accounting is subject to change through October 31, 2011.

August 19, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of July 31, 2011

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,439,351,593.82	$ 14,432,395.75	$ (1,404,000,051.78)	$ (14,388,500.44)	$ 35,351,542.04	$ 43,895.31
Add						
Net Income for Period ……………………………	108,446,911.58	-	955,982.10	-	109,402,893.68	-
Deductions:						
Common Dividends						
Common Stock Without Par Value....................	(68,000,000.00)	-	-	-	(68,000,000.00)	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc……………………….…………	(1,516,820.00)	1,516,820.00	516,882.45	(516,882.45)	(999,937.55)	999,937.55
Balance at End of Period …...…………………………	$ 1,478,281,685.40	$ 15,949,215.75	$ (1,402,527,187.23)	$ (14,905,382.89)	$ 75,754,498.17	$ 1,043,832.86
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings…………		15,949,215.75		(14,905,382.89)		1,043,832.86
Statutory Tax Rate…...…………………………………		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary…...………………		$ 6,204,244.93		$ (5,798,193.94)		$ 406,050.98

Note: Purchase accounting is subject to change through October 31, 2011

August 19, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of July 31, 2011

Retained Earnings and Undistributed Earnings	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,408,559,586.44	$ 13,513,838.75			$ 1,408,559,586.44	$ 13,513,838.75
Add						
Net Income for Period...	190,157,475.96	-	891,816.48	-	191,049,292.44	-
Purchase Accounting Deductions:			(1,404,083,566.85)	(14,240,819.75)	(1,404,083,566.85)	(14,240,819.75)
Deductions:						
Common Dividends						
Common Stock Without Par Value...................	(118,000,000.00)		-		(118,000,000.00)	
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	(2,435,377.00)	2,435,377.00	664,563.14	(664,563.14)	(1,770,813.86)	1,770,813.86
Balance at End of Period	$ 1,478,281,685.40	$ 15,949,215.75	$ (1,402,527,187.23)	$ (14,905,382.89)	$ 75,754,498.17	$ 1,043,832.86

Deferred Taxes Related to Undistributed Subsidiary Earnings	Without Purchase Accounting	Purchase Accounting	Combined
Balance of Undistributed Subsidiary Earnings................	15,949,215.75	(14,905,382.89)	1,043,832.86
Statutory Tax Rate...	38.9%	38.9%	38.9%
Deferred Taxes on Equity in Subsidiary..........................	$ 6,204,244.93	$ (5,798,193.94)	$ 406,050.98

Combined Balance of Retained Earnings	12 MONTHS 7/31/2011	12 MONTHS 7/31/2010
Retained Earnings at Beginning of Period.......................	$ 1,422,073,425.19	$ 1,243,306,758.79
Net Income for Period	191,049,292.44	178,766,666.40
FIN 48 Adjustment...	-	-
Subtotal..	1,613,122,717.63	1,422,073,425.19
Deduct		
Purchase Accounting Adjustment...............................	1,418,324,386.60	-
Dividends on Common Stock.....................................	118,000,000.00	-
Retained Earnings at End of Period.................................	$ 76,798,331.03	$ 1,422,073,425.19

Note: Purchase accounting is subject to change through October 31, 2011

August 19, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of July 31, 2011

Assets	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 6,608,149,389.52	$ -	$ 6,608,149,389.52
Less Reserves for Depreciation and Amortization.....	2,343,868,957.03	-	2,343,868,957.03
Total..	4,264,280,432.49	-	4,264,280,432.49
Investments			
Electric Energy, Inc...	13,185,620.55	17,057,119.86	30,242,740.41
Ohio Valley Electric Corporation.............................	250,000.00	-	250,000.00
Nonutility Property - Less Reserve...........................	179,120.94	-	179,120.94
Special Funds...	-	-	-
Total..	13,614,741.49	17,057,119.86	30,671,861.35
Current and Accrued Assets			
Cash..	36,032,578.20	-	36,032,578.20
Special Deposits...	405,895.98	-	405,895.98
Temporary Cash Investments..................................	12,237.44	-	12,237.44
Accounts Receivable-Less Reserve.........................	189,095,847.43	-	189,095,847.43
Accounts Receivable from Assoc Companies..........	236,912.87	-	236,912.87
Materials & Supplies-At Average Cost			
Fuel..	82,091,389.23	-	82,091,389.23
Plant Materials & Operating Supplies..................	32,983,715.02	-	32,983,715.02
Stores Expense..	9,807,522.54	-	9,807,522.54
Allowance Inventory..	501,513.10	-	501,513.10
Prepayments..	6,960,359.10	-	6,960,359.10
Miscellaneous Current & Accrued Assets..............	106,129.25	-	106,129.25
Total..	358,234,100.16	-	358,234,100.16
Deferred Debits and Other			
Unamortized Debt Expense......................................	21,851,844.40	(4,500,032.28)	17,351,812.12
Unamortized Loss on Bonds....................................	12,027,189.32	-	12,027,189.32
Accumulated Deferred Income Taxes.......................	76,681,026.30	69,181,824.41	145,862,850.71
Deferred Regulatory Assets.....................................	283,083,685.27	16,290,104.64	299,373,789.91
Other Deferred Debits..	44,360,914.74	159,923,226.19	204,284,140.93
Goodwill..	-	607,404,368.23	607,404,368.23
Total..	438,004,660.03	848,299,491.19	1,286,304,151.22
Total Assets..	$ 5,074,133,934.17	$ 865,356,611.05	$ 5,939,490,545.22

Note: Purchase accounting is subject to change through October 31, 2011

August 19, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of July 31, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Proprietary Capital			
Common Stock..	$ 308,139,977.56	$ -	$ 308,139,977.56
Less: Common Stock Expense....................................	321,288.87	-	321,288.87
Paid-In Capital..	315,858,083.00	2,032,588,750.94	2,348,446,833.94
Other Comprehensive Income.....................................	(2,474,626.63)	1,990,823.26	(483,803.37)
Retained Earnings...	1,478,281,685.40	(1,402,527,187.23)	75,754,498.17
Unappropriated Undistributed Subsidiary Earnings....	15,949,215.75	(14,905,382.89)	1,043,832.86
Total Proprietary Capital..	2,115,433,046.21	617,147,004.08	2,732,580,050.29
Pollution Control Bonds - Net of Reacquired Bonds...	350,779,405.00	1,111,725.58	351,891,130.58
First Mortgage Bonds..	1,489,547,468.75	-	1,489,547,468.75
Total Long-Term Debt..	1,840,326,873.75	1,111,725.58	1,841,438,599.33
Total Capitalization..	3,955,759,919.96	618,258,729.66	4,574,018,649.62
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Accounts Payable...	78,763,356.44	-	78,763,356.44
Accounts Payable to Associated Companies................	23,378,743.34	-	23,378,743.34
Customer Deposits...	23,337,255.65	-	23,337,255.65
Taxes Accrued..	26,769,889.12	-	26,769,889.12
Interest Accrued...	15,131,089.09	-	15,131,089.09
Dividends Declared..	-	-	-
Miscellaneous Current and Accrued Liabilities...........	21,498,930.21	-	21,498,930.21
Total..	188,879,263.85	-	188,879,263.85
Deferred Credits and Other			
Accumulated Deferred Income Taxes..........................	491,559,670.98	75,384,582.84	566,944,253.82
Investment Tax Credit..	102,574,479.32	-	102,574,479.32
Regulatory Liabilities...	115,411,913.60	159,923,226.19	275,335,139.79
Customer Advances for Construction..........................	3,162,568.61	-	3,162,568.61
Asset Retirement Obligations......................................	55,395,249.70	-	55,395,249.70
Other Deferred Credits...	24,253,215.69	11,790,072.36	36,043,288.05
Miscellaneous Long-Term Liabilities..........................	2,805,389.46	-	2,805,389.46
Accum Provision for Postretirement Benefits.............	134,332,263.00	-	134,332,263.00
Total..	929,494,750.36	247,097,881.39	1,176,592,631.75
Total Liabilities and Stockholders' Equity.........................	$ 5,074,133,934.17	$ 865,356,611.05	$ 5,939,490,545.22

Note: Purchase accounting is subject to change through October 31, 2011

August 19, 2011

KENTUCKY UTILITIES COMPANY

Financial Reports

June 30, 2011

Index
Financial and Operating Reports

Kentucky Utilities Company
June 30, 2011

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2011 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows, unless otherwise noted.

Kentucky Utilities Company
Comparative Statement of Income
June 30, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 133,025,751.99	$ 131,506,402.73	$ 1,519,349.26	1.16
Rate Refunds	-	(632,390.04)	632,390.04	100.00
Total Operating Revenues	133,025,751.99	130,874,012.69	2,151,739.30	1.64
Fuel for Electric Generation	51,080,753.18	53,171,657.03	(2,090,903.85)	(3.93)
Power Purchased	4,961,514.11	10,988,252.08	(6,026,737.97)	(54.85)
Other Operation Expenses	20,353,304.26	19,426,364.32	926,939.94	4.77
Maintenance	9,885,118.94	8,020,108.69	1,865,010.25	23.25
Depreciation	15,226,844.03	11,398,090.23	3,828,753.80	33.59
Amortization Expense	602,329.81	535,990.58	66,339.23	12.38
Regulatory Credits	(473,137.66)	(209,944.31)	(263,193.35)	(125.36)
Taxes				
Federal Income	(16,089,366.68)	(11,358,292.54)	(4,731,074.14)	(41.65)
State Income	(963,179.88)	(2,865,824.75)	1,902,644.87	66.39
Deferred Federal Income - Net	23,593,701.47	16,763,584.61	6,830,116.86	40.74
Deferred State Income - Net	2,074,513.77	3,766,561.57	(1,692,047.80)	(44.92)
Property and Other	2,313,840.66	1,647,615.49	666,225.17	40.44
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	-	-	-	-
Accretion Expense	229,165.18	185,199.36	43,965.82	23.74
Total Operating Expenses	112,795,401.19	111,469,362.36	1,326,038.83	1.19
Net Operating Income	20,230,350.80	19,404,650.33	825,700.47	4.26
Other Income Less Deductions				
Amortization of Investment Tax Credit	233,343.00	5,925.00	227,418.00	3,838.28
Other Income Less Deductions	609,872.64	(182,395.13)	792,267.77	434.37
AFUDC - Equity	3,787.83	(36,191.58)	39,979.41	110.47
Total Other Income Less Deductions	847,003.47	(212,661.71)	1,059,665.18	498.29
Income Before Interest Charges	21,077,354.27	19,191,988.62	1,885,365.65	9.82
Interest on Long-Term Debt	5,087,278.50	6,353,152.47	(1,265,873.97)	(19.93)
Amortization of Debt Expense - Net	320,194.75	68,470.36	251,724.39	367.64
Other Interest Expenses	618,531.83	337,516.79	281,015.04	83.26
AFUDC - Borrowed Funds	(1,155.51)	(70,926.92)	69,771.41	98.37
Total Interest Charges	6,024,849.57	6,688,212.70	(663,363.13)	(9.92)
Net Income	$ 15,052,504.70	$ 12,503,775.92	$ 2,548,728.78	20.38

July 27, 2011

Kentucky Utilities Company
Comparative Statement of Income
June 30, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues.....................................	$ 771,232,868.59	$ 730,542,999.47	$ 40,689,869.12	5.57
Rate Refunds..	-	(632,390.04)	632,390.04	100.00
Total Operating Revenues......................................	771,232,868.59	729,910,609.43	41,322,259.16	5.66
Fuel for Electric Generation......................................	257,419,703.04	244,728,743.31	12,690,959.73	5.19
Power Purchased...	57,694,127.77	94,257,124.40	(36,562,996.63)	(38.79)
Other Operation Expenses..	114,921,100.45	105,710,232.80	9,210,867.65	8.71
Maintenance..	63,263,719.43	49,411,285.50	13,852,433.93	28.04
Depreciation..	89,737,522.42	65,359,487.23	24,378,035.19	37.30
Amortization Expense...	3,498,810.87	3,312,304.13	186,506.74	5.63
Regulatory Credits..	(2,850,407.05)	(1,245,411.20)	(1,604,995.85)	(128.87)
Taxes				
Federal Income...	(3,174,533.87)	13,726,170.43	(16,900,704.30)	(123.13)
State Income...	4,509,943.73	1,540,178.70	2,969,765.03	192.82
Deferred Federal Income - Net...............................	48,680,498.78	23,499,265.38	25,181,233.40	107.16
Deferred State Income - Net...................................	2,692,792.20	5,096,830.24	(2,404,038.04)	(47.17)
Property and Other...	13,890,498.78	10,054,835.89	3,835,662.89	38.15
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances...........	(3,293.39)	(44,023.81)	40,730.42	92.52
Accretion Expense..	1,361,583.68	1,096,827.79	264,755.89	24.14
Total Operating Expenses......................................	651,642,066.84	616,503,850.79	35,138,216.05	5.70
Net Operating Income...	119,590,801.75	113,406,758.64	6,184,043.11	5.45
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	1,286,347.00	35,550.00	1,250,797.00	3,518.42
Other Income Less Deductions...........................	694,209.56	910,674.42	(216,464.86)	(23.77)
AFUDC - Equity...	14,145.38	(95,671.15)	109,816.53	114.79
Total Other Income Less Deductions.....................	1,994,701.94	850,553.27	1,144,148.67	134.52
Income Before Interest Charges.............................	121,585,503.69	114,257,311.91	7,328,191.78	6.41
Interest on Long-Term Debt......................................	30,738,892.42	38,181,461.96	(7,442,569.54)	(19.49)
Amortization of Debt Expense - Net.........................	1,803,028.70	410,449.24	1,392,579.46	339.28
Other Interest Expenses..	2,922,826.23	1,778,333.69	1,144,492.54	64.36
AFUDC - Borrowed Funds.......................................	(4,300.33)	(471,842.60)	467,542.27	99.09
Total Interest Charges..	35,460,447.02	39,898,402.29	(4,437,955.27)	(11.12)
Net Income..	$ 86,125,056.67	$ 74,358,909.62	$ 11,766,147.05	15.82

July 27, 2011

Kentucky Utilities Company
Comparative Statement of Income
June 30, 2011

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 1,553,031,965.04	$ 1,417,652,252.76	$ 135,379,712.28	9.55
Rate Refunds	6.12	(1,101,620.83)	1,101,626.95	100.00
Total Operating Revenues	1,553,031,971.16	1,416,550,631.93	136,481,339.23	9.63
Fuel for Electric Generation	508,775,147.86	463,665,547.76	45,109,600.10	9.73
Power Purchased	138,058,940.64	185,737,253.19	(47,678,312.55)	(25.67)
Other Operation Expenses	225,858,095.42	205,388,610.00	20,469,485.42	9.97
Maintenance	121,666,418.73	49,876,428.61	71,789,990.12	143.94
Depreciation	163,660,075.88	129,574,096.97	34,085,978.91	26.31
Amortization Expense	6,789,970.66	6,630,479.60	159,491.06	2.41
Regulatory Credits	(6,754,553.20)	(2,464,168.11)	(4,290,385.09)	(174.11)
Taxes				
Federal Income	44,758,744.98	17,644,200.68	27,114,544.30	153.67
State Income	15,726,157.54	2,395,722.48	13,330,435.06	556.43
Deferred Federal Income - Net	47,456,685.15	59,959,074.48	(12,502,389.33)	(20.85)
Deferred State Income - Net	907,000.14	12,683,650.17	(11,776,650.03)	(92.85)
Property and Other	23,729,141.86	19,237,609.56	4,491,532.30	23.35
Investment Tax Credit	-	10,708,227.54	(10,708,227.54)	(100.00)
Loss (Gain) from Disposition of Allowances	(16,020.32)	(44,023.81)	28,003.49	63.61
Accretion Expense	3,763,660.83	2,164,328.96	1,599,331.87	73.90
Total Operating Expenses	1,294,379,466.17	1,163,157,038.08	131,222,428.09	11.28
Net Operating Income	258,652,504.99	253,393,593.85	5,258,911.14	2.08
Other Income Less Deductions				
Amortization of Investment Tax Credit	1,321,897.00	107,319.50	1,214,577.50	1,131.74
Other Income Less Deductions	841,449.06	(1,171,465.20)	2,012,914.26	171.83
AFUDC - Equity	630,968.57	1,182,713.73	(551,745.16)	(46.65)
Total Other Income Less Deductions	2,794,314.63	118,568.03	2,675,746.60	2,256.72
Income Before Interest Charges	261,446,819.62	253,512,161.88	7,934,657.74	3.13
Interest on Long-Term Debt	67,001,872.68	75,173,914.75	(8,172,042.07)	(10.87)
Amortization of Debt Expense - Net	2,581,521.37	820,634.33	1,760,887.04	214.58
Other Interest Expenses	5,103,915.51	3,419,727.53	1,684,187.98	49.25
AFUDC - Borrowed Funds	(501,054.66)	(1,016,392.77)	515,338.11	50.70
Total Interest Charges	74,186,254.90	78,397,883.84	(4,211,628.94)	(5.37)
Net Income	$ 187,260,564.72	$ 175,114,278.04	$ 12,146,286.68	6.94

July 27, 2011

Kentucky Utilities Company
Analysis of Retained Earnings
June 30, 2011

	Current Month		Year to Date		Year Ended Current Month	
Retained Earnings and Undistributed Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period	$ 1,441,543,639.79	$ 15,312,901.75	$ 1,439,351,593.82	$ 14,432,395.75	$ 1,390,181,898.77	$ 12,466,582.75
Add:						
Net Income for Period	15,052,504.70	-	86,125,056.67	-	187,260,564.72	-
Deduct:						
Common Dividends						
Common Stock Without Par Value	-	-	(68,000,000.00)	-	(118,000,000.00)	-
EE Inc.	(139,383.00)	139,383.00	(1,019,889.00)	1,019,889.00	(2,985,702.00)	2,985,702.00
Balance at End of Period	$ 1,456,456,761.49	$ 15,452,284.75	$ 1,456,456,761.49	$ 15,452,284.75	$ 1,456,456,761.49	$ 15,452,284.75
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings		15,452,284.75		15,452,284.75		15,452,284.75
Statutory Tax Rate		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary		$ 6,010,938.77		$ 6,010,938.77		$ 6,010,938.77

July 27, 2011

Kentucky Utilities Company
Comparative Balance Sheets as of June 30, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,588,253,087.34	$ 6,276,682,344.79
Less: Reserves for Depreciation and Amortization	2,329,491,482.53	2,211,792,190.53
Total	4,258,761,604.81	4,064,890,154.26
Investments		
Electric Energy, Inc.	12,674,129.55	13,762,382.75
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	179,120.94	179,120.94
Total	13,103,250.49	14,191,503.69
Current and Accrued Assets		
Cash	6,817,643.07	3,260,639.89
Special Deposits	640,705.40	-
Temporary Cash Investments	12,114.69	269.25
Accounts Receivable-Less Reserve	165,764,056.58	198,144,345.75
Accounts Receivable from Associated Companies	5,001,224.57	3,579.45
Materials and Supplies-At Average Cost		
Fuel	92,538,396.90	113,321,445.77
Plant Materials and Operating Supplies	33,129,391.71	31,728,422.13
Stores Expense	9,723,255.58	8,322,493.96
Emission Allowances	512,525.39	693,049.19
Prepayments	7,923,784.79	4,095,519.82
Miscellaneous Current and Accrued Assets	98,710.66	66,114.27
Total	322,161,809.34	359,635,879.48
Deferred Debits and Other		
Unamortized Debt Expense	21,814,142.64	4,734,759.89
Unamortized Loss on Bonds	12,077,603.71	12,682,576.39
Accumulated Deferred Income Taxes	76,681,026.30	46,858,854.08
Deferred Regulatory Assets	279,417,797.15	235,550,067.56
Other Deferred Debits	44,251,239.15	40,994,125.01
Total	434,241,808.95	340,820,382.93
Total Assets	$ 5,028,268,473.59	$ 4,779,537,920.36

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	315,858,083.00	315,858,083.00
Other Comprehensive Income	(2,489,186.63)	-
Retained Earnings	1,456,456,761.49	1,390,181,898.77
Unappropriated Undistributed Subsidiary Earnings	15,452,284.75	12,466,582.75
Total Proprietary Capital	2,093,096,631.30	2,026,325,253.21
Pollution Control Bonds	350,779,405.00	350,779,405.00
First Mortgage Bonds	1,489,494,531.25	-
LT Notes Payable to Associated Companies	-	1,298,000,000.00
Total Long-Term Debt	1,840,273,936.25	1,648,779,405.00
Total Capitalization	3,933,370,567.55	3,675,104,658.21
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	117,053,954.00
Accounts Payable	76,456,703.25	97,454,533.92
Accounts Payable to Associated Companies	26,344,328.96	66,000,291.75
Customer Deposits	23,299,986.50	22,433,452.56
Taxes Accrued	11,293,906.28	6,856,292.95
Interest Accrued	10,004,371.62	311,860.57
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	21,000,490.72	18,587,310.27
Total	168,399,787.33	328,697,696.02
Deferred Credits and Other		
Accumulated Deferred Income Taxes	491,559,670.98	409,153,631.96
Investment Tax Credit	102,807,822.32	104,129,719.32
Regulatory Liabilities	113,430,635.84	45,997,441.50
Customer Advances for Construction	3,173,808.69	3,020,822.22
Asset Retirement Obligations	55,284,494.83	35,447,299.20
Other Deferred Credits	22,009,407.47	24,519,476.04
Miscellaneous Long-Term Liabilities	2,805,389.46	2,660,205.61
Accum Provision for Postretirement Benefits	135,426,889.12	150,806,970.28
Total	926,498,118.71	775,735,566.13
Total Liabilities and Stockholders Equity	$ 5,028,268,473.59	$ 4,779,537,920.36

July 27, 2011

Kentucky Utilities Company
Statement of Capitalization and Short-Term Debt
June 30, 2011

	Authorized Shares	Issued and Outstanding Shares	Issued and Outstanding Amount	Percent of Total Capital
Proprietary Capital				
Common Stock - Without Par...	80,000,000	37,817,878	$ 308,139,977.56	
Less: Common Stock Expense..			321,288.87	
Paid-In Capital..			315,858,083.00	
Other Comprehensive Income...			(2,489,186.63)	
Retained Earnings...			1,456,456,761.49	
Unappropriated Undistributed Subsidiary Earnings.............			15,452,284.75	
Total Proprietary Capital..			2,093,096,631.30	53.21
Long-Term Debt				
Pollution Control Bonds				
Mercer County 2000 Series A due 05/01/23 Var%..........			12,900,000.00	
Carroll County 2002 Series A due 02/01/32 Var%..........			20,930,000.00	
Carroll County 2002 Series B due 02/01/32 Var%..........			2,400,000.00	
Carroll County 2002 Series C due 10/01/32 Var%..........			96,000,000.00	
Mercer County 2002 Series A due 02/01/32 Var%..........			7,400,000.00	
Muhlenburg County 2002 Series A due 02/01/32 Var%...			2,400,000.00	
Carroll County 2004 Series A due 10/01/34 Var%..........			50,000,000.00	
Carroll County 2006 Series B due 10/01/34 Var%..........			54,000,000.00	
Carroll County 2007 Series A due 02/01/26 5.75%.........			17,875,000.00	
Trimble County 2007 Series A due 03/01/37 6.00%.........			8,927,000.00	
Carroll County 2008 Series A due 02/01/32 Var%..........			77,947,405.00	
Total Pollution Control Bonds..			350,779,405.00	8.92
First Mortgage Bonds				
First Mortgage Bond Due 11/01/15 1.625%......................			250,000,000.00	
First Mortgage Bond Due 11/01/20 3.250%.....................			500,000,000.00	
First Mortgage Bond Due 11/01/40 5.125%.....................			750,000,000.00	
Total First Mortgage Bonds..			1,500,000,000.00	38.14
Less: First Mortgage Bonds Debt Discount				
First Mortgage Bond Due 11/01/15 1.625%......................			(765,625.00)	
First Mortgage Bond Due 11/01/20 3.250%.....................			(1,771,875.00)	
First Mortgage Bond Due 11/01/40 5.125%.....................			(7,967,968.75)	
			(10,505,468.75)	(0.27)
Total First Mortgage Bonds - Net of Debt Discount............			1,489,494,531.25	37.87
Total Capitalization..			$ 3,933,370,567.55	100.00

July 27, 2011

Kentucky Utilities Company
Summary Trial Balance
June 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 6,588,253,087.34	$ 6,588,253,087.34
Reserves for Depreciation and Amortization		(2,329,491,482.53)
Depreciation of Plant	(2,313,618,550.18)	
Amortization of Plant	(15,872,932.35)	
Investments		13,103,250.49
Electric Energy, Inc	12,674,129.55	
Ohio Valley Electric Corporation	250,000.00	
Nonutility Property Reserve	179,120.94	
Cash	6,817,643.07	6,817,643.07
Special Deposits		640,705.40
MAN Margin Call	640,705.40	
Temporary Cash Investments	12,114.69	12,114.69
Accounts Receivable - Less Reserve		165,764,056.58
Unbilled Revenues	77,917,735.64	
Customers - Active	75,846,802.69	
Bechtel Liquidated Damages	6,335,010.00	
IMPA	1,917,682.95	
IMEA	1,804,546.44	
Transmission Sales	1,008,594.30	
Damage Claims	363,003.28	
IMEA/IMPA Net Portion of Bechtel Liquidated damages	(1,583,832.50)	
Other	4,509,437.91	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	3,541,899.33	
Reserve	(2,059,390.00)	
Accrual	(2,957,265.76)	
Recoveries	(584,352.57)	
A/R Miscellaneous	(295,815.13)	
Accounts Receivable from Associated Companies		5,001,224.57
LG&E - KU Energy Services/Louisville Gas and Electric Company	5,001,224.57	
Fuel		92,538,396.90
Coal 1,522,615.48 Tons @ $55.84 MMBtu 35,025,429.57 @ 242.74¢	85,022,430.42	
Fuel Oil 2,980,810.00 Gallons @ 249.84¢	7,447,258.29	
Gas Pipeline 12,248.00 Mcf @ $5.61	68,708.19	
Plant Materials and Operating Supplies		33,129,391.71
Regular Materials and Supplies	32,510,081.67	
Limestone 71,667.99 Tons @ $8.64	619,310.01	
Other Reagents	0.03	
Stores Expense Undistributed	9,723,255.58	9,723,255.58

July 27, 2011

Kentucky Utilities Company
Summary Trial Balance
June 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Emission Allowances	$ 512,525.39	$ 512,525.39
Prepayments		7,923,784.79
Insurance	4,383,452.57	
Taxes	2,017,354.26	
Lease	671,493.28	
Risk Management and Workers Compensation	75,000.00	
Other	776,484.68	
Miscellaneous Current Assets		98,710.66
Derivative Asset - Non-Hedging	98,710.66	
Unamortized Debt Expense		21,814,142.64
Carroll County 2002 Series A due 02/01/32 Var%	84,396.34	
Carroll County 2002 Series B due 02/01/32 Var%	58,657.62	
Carroll County 2002 Series C due 10/01/32 Var%	1,565,232.36	
Mercer County 2002 Series A due 02/01/32 Var%	23,558.40	
Muhlenburg County 2002 Series A due 02/01/32 Var%	65,297.11	
Carroll County 2006 Series B due 10/01/34 Var%	1,114,140.78	
Carroll County 2007 Series A due 02/01/26 5.75%	486,239.31	
Trimble County 2007 Series A due 03/01/37 6.00%	412,506.40	
Carroll County 2008 Series A due 02/01/32 Var%	708,059.93	
First Mortgage Bond due 11/01/15 1.625%	1,904,065.19	
First Mortgage Bond due 11/01/20 3.250%	3,812,251.68	
First Mortgage Bond due 11/01/40 5.125%	7,226,266.38	
Revolving Credit Agreement	4,353,471.14	
Unamortized Loss on Bonds		12,077,603.71
Refinanced and Called Bonds	12,077,603.71	
Accumulated Deferred Income Taxes		76,681,026.30
Federal	64,935,848.93	
State	11,745,177.37	
Regulatory Assets		279,417,797.15
Pension and Postretirement Benefits	117,274,368.11	
SFAS 109 - Deferred Taxes	77,275,037.46	
2009 Winter Storm	51,990,055.64	
Virginia Mountain Snowstorm	6,041,670.12	
FERC Jurisdictional Pension Expense	5,355,251.78	
VA Fuel Component Non-Current	4,919,000.00	
MISO Exit Fee	4,427,644.81	
Asset Retirement Obligations	4,342,860.49	
Fuel Adjustment Clause	2,213,000.00	
2008 Wind Storm	1,994,260.68	
Rate Case Expenses	1,706,045.12	
EKPC FERC Transmission Cost	892,525.50	
KCCS Funding	710,677.89	
CMRG Funding	213,416.63	
General Management Audit	61,982.92	
Other Deferred Debits	44,251,239.15	44,251,239.15
Total Assets	$ 5,028,268,473.59	$ 5,028,268,473.59

July 27, 2011

Kentucky Utilities Company
Summary Trial Balance
June 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 2,093,096,631.30
Common Stock	308,139,977.56	
Less: Common Stock Expense	321,288.87	
Paid-In Capital	315,858,083.00	
Other Comprehensive Income	(2,489,186.63)	
Retained Earnings	1,456,456,761.49	
Unappropriated Undistributed Subsidiary Earnings	15,452,284.75	
Bonds		1,840,273,936.25
Pollution Control Bonds - Net of Reacquired Bonds	350,779,405.00	
First Mortgage Bonds	1,489,494,531.25	
Accounts Payable		76,456,703.25
Regular	73,822,544.84	
Salaries and Wages Accrued	2,627,948.85	
Employee Withholdings Payable	6,209.56	
Accounts Payable to Associated Companies		26,344,328.96
LG&E - KU Energy Services/Louisville Gas and Electric Company	26,344,328.96	
Customers' Deposits	23,299,986.50	23,299,986.50
Taxes Accrued	11,293,906.28	11,293,906.28
Interest Accrued		10,004,371.62
Mercer County 2000 Series A due 05/01/23 Var%	1,399.56	
Carroll County 2002 Series A due 02/01/32 Var%	8,199.97	
Carroll County 2002 Series B due 02/01/32 Var%	315.62	
Carroll County 2002 Series C due 10/01/32 Var%	4,320.00	
Mercer County 2002 Series A due 02/01/32 Var%	973.15	
Muhlenburg County 2002 Series A due 02/01/32 Var%	315.62	
Carroll County 2004 Series A due 10/01/34 Var%	6,410.96	
Carroll County 2006 Series B due 10/01/34 Var%	7,175.34	
Carroll County 2007 Series A due 02/01/26 5.75%	85,651.04	
Trimble County 2007 Series A due 03/01/37 6.00%	44,635.00	
Carroll County 2008 Series A due 02/01/32 Var%	9,930.29	
First Mortgage Bond due 11/01/15 1.625%	677,083.34	
First Mortgage Bond due 11/01/20 3.250%	2,708,333.34	
First Mortgage Bond due 11/01/40 5.125%	6,406,250.00	
Customers' Deposits	17,516.71	
Other	25,861.68	

July 27, 2011

Kentucky Utilities Company
Summary Trial Balance
June 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Miscellaneous Current and Accrued Liabilities		$ 21,000,490.72
Vacation Pay Accrued	6,700,744.77	
Franchise Fee Payable	4,887,037.67	
Tax Collections Payable	4,388,187.32	
Customer Overpayments	4,187,078.91	
Derivative Liabilities - Non-Hedging	393,528.55	
Home Energy Assistance	354,910.39	
Escheated Deposits	(200.91)	
Other	89,204.02	
Accumulated Deferred Income Taxes		491,559,670.98
Federal	427,861,146.32	
State	63,698,524.66	
Investment Tax Credit		102,807,822.32
Advanced Coal Credit	99,999,201.00	
Job Development Credit	2,808,621.32	
Regulatory Liabilities		113,430,635.84
Deferred Taxes		
Federal	62,438,640.72	
State	19,612,490.70	
Postretirement Benefits	9,787,090.00	
Environmental Cost Recovery	8,722,553.15	
DSM Cost Recovery	5,598,533.63	
Asset Retirement Obligations	4,501,711.55	
Spare Parts	1,906,297.00	
MISO Schedule 10 Charges	863,319.09	
Customers' Advances for Construction		3,173,808.69
Line Extensions	2,353,451.01	
Customer Advances	93,678.30	
Other	726,679.38	
Asset Retirement Obligations	55,284,494.83	55,284,494.83
Other Deferred Credits	22,009,407.47	22,009,407.47
Miscellaneous Long-Term Liabilities		2,805,389.46
Workers' Compensation	2,805,389.46	
Accumulated Provision for Benefits		135,426,889.12
Pension Payable	70,301,999.50	
Postretirement Benefits - SFAS 106	65,673,978.97	
Post Employment Benefits Payable	5,554,516.00	
Post Employment Medicare Subsidy	(382,793.62)	
Medicare Subsidy - SFAS 106	(5,720,811.73)	
Total Liabilities and Stockholders Equity	$ 5,028,268,473.59	$ 5,028,268,473.59

July 27, 2011

Kentucky Utilities Company
Statement of Cash Flows
June 30, 2011

	Year to Date 2011	Year to Date 2010
Cash Flows from Operating Activities		
Net income...	$ 86,125,056.67	$ 74,358,909.62
Items not requiring (providing) cash currently:		
Depreciation…………………..	89,737,522.42	65,359,487.23
Amortization…………………...	3,498,810.87	3,312,304.13
Deferred income taxes - net..	52,818,076.11	28,596,095.62
Investment Tax Credit………………………………………	(1,321,895.00)	-
Gain on disposal of assets...	88,224.58	(2,190.54)
Other…………………...	(192,639.70)	11,225,708.92
Change in receivables...	23,196,543.41	(15,999,717.11)
Change in inventory...	1,214,284.86	(17,677,648.64)
Change in allowance inventory..	54,053.61	282,026.71
Change in payables and accrued expenses...............................	(30,802,127.83)	(13,158,025.16)
Change in regulatory assets..	(64,408,456.89)	18,121,681.49
Change in regulatory liabilities..	58,318,005.44	1,752,998.10
Change in other deferred debits..	(14,351,244.82)	(577,218.49)
Change in other deferred credits...	13,645,313.89	14,641,160.04
Pension and postretirement funding…………………………	(45,195,100.00)	(15,447,100.00)
Other..	9,188,055.91	2,784,576.39
Less: Allowance for other funds used during construction.......	(9,845.05)	(376,171.45)
Less: Undistributed earnings of subsidiary company................	(1,019,889.00)	(1,795,214.00)
Net cash provided (used) by operating activities....................	180,582,749.48	155,401,662.86
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures......	(91,706,597.22)	(193,286,987.78)
Less: Allowance for other funds used during construction.......	9,845.05	376,171.45
Proceeds received from sales of property……………………	(75,739.60)	-
Change in derivatives..	-	19,220.08
Change in restricted cash………………………………………	-	-
Other...	(5,096,413.18)	-
Net cash provided (used) by investing activities..................…	(96,868,904.95)	(192,891,596.25)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt…………................	(1,783,533.63)	(514.80)
Net change in short-term debt..	(10,434,000.00)	39,079,000.00
Dividends on common stock…………………………………	(68,000,000.00)	-
Net cash provided (used) by financing activities....................	(80,217,533.63)	39,078,485.20
Net Increase (Decrease) in Cash and Cash Equivalents…………	3,496,310.90	1,588,551.81
Cash and Cash Equivalents at Beginning of Period……………	3,333,446.86	1,672,357.33
Cash and Cash Equivalents at End of Period……………………	$ 6,829,757.76	$ 3,260,909.14

July 27, 2011

Kentucky Utilities Company
Analysis of Interest Charges
June 30, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Interest on Long-Term Debt						
Loan Agreement - Pollution Control Bonds						
Mercer County 2000 Series A due 05/01/23 Var%..............	$ 1,304.14	$ 3,930.00	$ 14,931.78	$ 19,215.62	$ 37,925.59	$ 46,029.96
Carroll County 2002 Series A due 02/01/32 Var%..............	12,099.26	10,378.99	112,385.52	76,982.28	183,834.24	194,075.58
Carroll County 2002 Series B due 02/01/32 Var%..............	1,472.88	1,190.14	12,767.21	8,827.40	20,960.08	22,254.24
Carroll County 2002 Series C due 10/01/32 Var%..............	16,752.00	55,973.33	151,850.76	408,749.29	430,901.43	549,330.61
Mercer County 2002 Series A due 02/01/32 Var%..............	4,541.37	3,669.59	38,186.04	27,217.82	63,447.41	68,617.27
Muhlenburg County 2002 Series A due 02/01/32 Var%.......	1,472.88	1,190.14	12,384.70	8,827.40	20,577.57	22,254.24
Carroll County 2004 Series A due 10/01/34 Var%..............	6,410.96	13,835.62	65,520.44	71,301.37	144,520.44	154,698.64
Carroll County 2006 Series B due 10/01/34 Var%..............	7,175.34	14,809.32	72,049.31	81,710.15	156,807.11	190,124.41
Carroll County 2007 Series A due 02/01/26 5.75%.............	85,651.04	85,651.04	513,906.25	513,906.25	1,027,812.50	1,027,812.50
Trimble County 2007 Series A due 03/01/37 6.00%............	44,635.00	44,635.00	267,810.00	267,810.00	535,620.00	535,620.00
Carroll County 2008 Series A due 02/01/32 Var%..............	9,930.29	21,376.81	102,100.41	117,839.38	224,488.51	273,815.35
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/01/15 1.625%.........................	338,541.67	-	2,031,250.00	-	2,539,062.51	-
First Mortgage Bond due 11/01/20 3.250%.........................	1,354,166.67	-	8,125,000.00	-	10,156,250.01	-
First Mortgage Bond due 11/01/40 5.125%.........................	3,203,125.00	-	19,218,750.00	-	24,023,437.50	-
Fidelia/PPL..	-	6,096,512.49	-	36,579,075.00	27,436,227.78	72,089,281.95
Total..	5,087,278.50	6,353,152.47	30,738,892.42	38,181,461.96	67,001,872.68	75,173,914.75
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense..................................	269,780.36	18,055.97	1,500,542.36	108,118.08	1,976,548.69	216,077.98
Amortization of Loss on Reacquired Debt...............................	50,414.39	50,414.39	302,486.34	302,331.16	604,972.68	604,556.35
Total..	320,194.75	68,470.36	1,803,028.70	410,449.24	2,581,521.37	820,634.33
Other Interest Charges						
Customers' Deposits..	147,489.90	134,782.93	683,458.32	741,372.88	1,305,655.31	1,273,656.65
Other Tax Deficiencies..	84,914.00	567.07	-	1,139.07	86,502.00	1,139.07
Interest on DSM Cost Recovery..	1,610.53	(795.21)	3,632.53	10,544.29	11,468.93	65,318.88
Interest on Debt to Associated Companies..............................	897.69	19,426.46	5,314.17	56,179.77	76,177.81	72,546.20
AFUDC Borrowed Funds..	(1,155.51)	(70,926.92)	(4,300.33)	(471,842.60)	(501,054.66)	(1,016,392.77)
Other Interest Expense..	383,619.71	183,535.54	2,230,421.21	969,097.68	3,624,111.46	2,007,066.73
Total..	617,376.32	266,589.87	2,918,525.90	1,306,491.09	4,602,860.85	2,403,334.76
Total Interest..	$ 6,024,849.57	$ 6,688,212.70	$ 35,460,447.02	$ 39,898,402.29	$ 74,186,254.90	$ 78,397,883.84

July 27, 2011

Kentucky Utilities Company
Analysis of Taxes Charged and Accrued
June 30, 2011

Kind of Taxes	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year
Taxes Charged to Accounts 408.1 and 409.1...........				
Property Taxes..	$ 1,494,264.00	$ 908,194.01	$ 8,970,215.77	$ 5,449,164.06
Unemployment..	4,481.51	4,333.76	82,617.23	84,713.45
FICA...	654,962.74	576,848.67	3,854,427.56	3,546,991.71
Public Service Commission Fee..............................	157,659.42	156,290.93	945,956.27	937,745.78
Federal Income..	(16,089,366.68)	(11,358,292.54)	(3,174,533.87)	13,726,170.43
State Income..	(963,179.88)	(2,865,824.75)	4,509,943.73	1,540,178.70
Miscellaneous..	2,472.99	1,948.12	37,281.95	36,220.89
Total Charged to Operating Expense..........	(14,738,705.90)	(12,576,501.80)	15,225,908.64	25,321,185.02
Taxes Charged to Other Accounts..........................	455,057.89	15,759,931.03	2,597,454.27	16,677,502.92
Taxes Accrued on Intercompany Accounts............	(336,525.22)	(255,904.51)	(2,152,626.09)	(1,576,975.59)
Total Taxes Charged.................................	$ (14,620,173.23)	$ 2,927,524.72	$ 15,670,736.82	$ 40,421,712.35

Analysis of Taxes Accrued - Account 236

Kind of Taxes	Taxes Accrued At Beginning Of Year	Accruals To Date This Year	Payments To Date This Year	Taxes Accrued At End Of Month
Property Taxes..	$ 8,399,528.00	$ 8,971,217.77	$ 8,102,594.49	$ 9,268,151.28
Unemployment..	75,728.12	58,702.69	133,776.50	654.31
FICA...	639,011.24	3,076,393.87	3,311,603.96	403,801.15
Federal Income..	12,876,014.95	(3,423,116.35)	9,041,229.00	411,669.60
State Income..	2,021,178.48	4,915,492.54	6,250,451.00	686,220.02
Kentucky Sales and Use Tax..................................	581,659.33	1,962,967.30	2,032,650.78	511,975.85
Miscellaneous..	21,662.86	109,079.00	119,307.79	11,434.07
Totals..	$ 24,614,782.98	$ 15,670,736.82	$ 28,991,613.52	$ 11,293,906.28

July 27, 2011

Kentucky Utilities Company
Summary of Utility Plant
June 30, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 Utility Plant in Service						
Electric						
Electric Distribution	$ 1,312,664,325.73	$ 32,873,827.31	$ (8,256,081.08)	$ 787,154.19	$ 25,404,900.42	$ 1,338,069,226.15
Electric General Plant	125,243,994.19	8,038,626.37	(4,012,715.91)	(787,154.19)	3,238,756.27	128,482,750.46
Electric Hydro Production	16,848,655.18	300,776.20	(15,190.72)	-	285,585.48	17,134,240.66
Electric Intangible Plant	49,640,906.77	4,853,531.59	(1,381,084.50)	-	3,472,447.09	53,113,353.86
Electric Other Production	519,412,128.33	2,764,320.78	(303,621.05)	-	2,460,699.73	521,872,828.06
Electric Steam Production	1,814,421,935.78	723,987,727.29	(4,905,686.26)	120,828,152.53	839,910,193.56	2,654,332,129.34
Electric Transmission	552,965,733.49	6,376,754.79	(1,216,238.11)	-	5,160,516.68	558,126,250.17
Total 101 Accounts	4,391,197,679.47	779,195,564.33	(20,090,617.63)	120,828,152.53	879,933,099.23	5,271,130,778.70
102 Electric Plant Purchased or Sold						
Electric						
Electric Steam	483,341.17	-	-	-	-	483,341.17
Total 102001	483,341.17	-	-	-	-	483,341.17
105 Plant Held for Future Use						
Electric						
Electric Distribution	792,599.21	-	-	-	-	792,599.21
Electric Steam	120,828,152.53	-	-	(120,828,152.53)	(120,828,152.53)	-
Total 105001	121,620,751.74	-	-	(120,828,152.53)	(120,828,152.53)	792,599.21
106 Completed Construction Not Classified						
Electric						
Electric Distribution	36,610,963.62	2,917,973.82	-	-	2,917,973.82	39,528,937.44
Electric General Plant	769,342.30	3,301,857.23	-	-	3,301,857.23	4,071,199.53
Electric Hydro Production	-	-	-	-	-	-
Electric Intangible Plant	2,685,464.69	646,155.85	-	-	646,155.85	3,331,620.54
Electric Other Production	3,737,695.33	(505,478.34)	-	-	(505,478.34)	3,232,216.99
Electric Steam Production	910,748,505.16	(6,984,053.64)	-	-	(6,984,053.64)	903,764,451.52
Electric Transmission	74,497,274.43	4,593,714.22	-	-	4,593,714.22	79,090,988.65
Total 106 Accounts	1,029,049,245.53	3,970,169.14	-	-	3,970,169.14	1,033,019,414.67
121 Nonutility Property						
Common						
Non Utility Property	179,120.94	-	-	-	-	179,120.94
Total 121001	179,120.94	-	-	-	-	179,120.94
107 Construction Work In Progress						
Electric						
Electric	954,430,277.48	(671,603,323.89)	-	-	(671,603,323.89)	282,826,953.59
Total 107001	954,430,277.48	(671,603,323.89)	-	-	(671,603,323.89)	282,826,953.59
Total Plant (Non-CWIP)	5,542,530,138.85	783,165,733.47	(20,090,617.63)	-	763,075,115.84	6,305,605,254.69
Total Plant + CWIP	6,496,960,416.33	111,562,409.58	(20,090,617.63)	-	91,471,791.95	6,588,432,208.28
Total Plant + CWIP - Nonutility (BS)	$ 6,496,781,295.39	$ 111,562,409.58	$ (20,090,617.63)	$ -	$ 91,471,791.95	$ 6,588,253,087.34

July 27, 2011

Kentucky Utilities Company
Summary of Utility Plant - Reserve for Depreciation of Utility Plant
June 30, 2011

	Beginning Balance	Accruals	Retirements	Transfers/ Adjustments	ARO Settlements	RWIP Transfers Out	Cost of Removal	Salvage	Other Credits	Ending Balance
Life Reserve										
Electric Distribution......................................	$ (398,692,068.83)	$ (13,736,343.59)	$ 8,256,081.08	$ (181,198.53)	$ -	$ -	$ -	$ -	$ -	$ (404,353,529.87)
Electric Distribution - ARO..........................	(790.87)	(2,216.70)	-	-	-	-	-	-	-	(3,007.57)
Electric General Plant...................................	(57,721,732.75)	(2,959,062.06)	4,012,715.91	181,198.53	-	-	-	-	-	(56,486,880.37)
Electric Hydro Production............................	(7,765,077.65)	(59,566.58)	15,190.72	-	-	-	-	-	-	(7,809,453.51)
Electric Hydro Production - ARO................	(121.57)	(486.48)	-	-	-	-	-	-	-	(608.05)
Electric Other Production.............................	(160,412,820.60)	(8,360,887.34)	303,621.05	-	-	-	-	-	-	(168,470,086.89)
Electric Other Production - ARO.................	(84.76)	(339.42)	-	-	-	-	-	-	-	(424.18)
Electric Steam Production............................	(1,067,997,942.05)	(44,011,905.65)	4,880,390.10	-	-	-	-	-	-	(1,107,129,457.60)
Electric Steam Production - ARO................	(485,952.30)	(1,485,152.57)	25,296.16	-	-	-	-	-	-	(1,945,808.71)
Electric Transmission...................................	(211,361,531.11)	(4,608,821.65)	1,216,238.11	-	-	-	-	-	-	(214,754,114.65)
Electric Transmission - ARO.......................	(156.99)	(628.20)	-	-	-	-	-	-	-	(785.19)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(1,904,438,279.48)	(75,225,410.24)	18,709,533.13	-	-	-	-	-	-	(1,960,954,156.59)
Cost of Removal										
Electric Distribution......................................	(195,818,054.42)	(4,017,711.51)	-	0.02	-	-	1,333,284.83	-	-	(198,502,481.08)
Electric General Plant...................................	207,510.70	(22,187.89)	-	(0.02)	-	-	23,483.98	-	-	208,806.77
Electric Hydro Production............................	(374,056.75)	(2,600.04)	-	-	-	-	29,260.00	-	-	(347,396.79)
Electric Other Production.............................	(3,174,464.89)	(448,028.46)	-	-	-	-	64,009.38	-	-	(3,558,483.97)
Electric Steam Production............................	(113,988,699.33)	(12,394,452.04)	-	-	-	-	1,595,496.60	-	-	(124,787,654.77)
Electric Transmission...................................	(137,175,896.62)	(1,390,753.53)	-	-	-	-	857,899.90	-	-	(137,708,750.25)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(450,323,661.31)	(18,275,733.47)	-	-	-	-	3,903,434.69	-	-	(464,695,960.09)
Salvage										
Electric Distribution......................................	48,221,606.07	979,837.82	-	-	-	-	-	(145,270.29)	-	49,056,173.60
Electric General Plant...................................	149,758.57	-	-	-	-	-	-	-	-	149,758.57
Electric Hydro Production............................	46,518.69	-	-	-	-	-	-	-	-	46,518.69
Electric Other Production.............................	618,891.61	-	-	-	-	-	-	-	-	618,891.61
Electric Steam Production............................	20,938,580.66	2,358,496.97	-	-	-	-	-	(1,151,553.50)	-	22,145,524.13
Electric Transmission...................................	23,009,336.80	322,915.93	-	-	-	-	-	(8,783.79)	-	23,323,468.94
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	92,984,692.40	3,661,250.72	-	-	-	-	-	(1,305,607.58)	-	95,340,335.54
Total Reserves										
Electric Distribution......................................	(546,288,517.18)	(16,774,217.28)	8,256,081.08	(181,198.51)	-	-	1,333,284.83	(145,270.29)	-	(553,799,837.35)
Electric Distribution - ARO..........................	(790.87)	(2,216.70)	-	-	-	-	-	-	-	(3,007.57)
Electric General Plant...................................	(57,364,463.48)	(2,981,249.95)	4,012,715.91	181,198.51	-	-	23,483.98	-	-	(56,128,315.03)
Electric Hydro Production............................	(8,092,615.71)	(62,166.62)	15,190.72	-	-	-	29,260.00	-	-	(8,110,331.61)
Electric Hydro Production - ARO................	(121.57)	(486.48)	-	-	-	-	-	-	-	(608.05)
Electric Other Production.............................	(162,968,393.88)	(8,808,915.80)	303,621.05	-	-	-	64,009.38	-	-	(171,409,679.25)
Electric Other Production - ARO.................	(84.76)	(339.42)	-	-	-	-	-	-	-	(424.18)
Electric Steam Production............................	(1,161,048,060.72)	(54,047,860.72)	4,880,390.10	-	-	-	1,595,496.60	(1,151,553.50)	-	(1,209,771,588.24)
Electric Steam Production - ARO................	(485,952.30)	(1,485,152.57)	25,296.16	-	-	-	-	-	-	(1,945,808.71)
Electric Transmission...................................	(325,528,090.93)	(5,676,659.25)	1,216,238.11	-	-	-	857,899.90	(8,783.79)	-	(329,139,395.96)
Electric Transmission - ARO.......................	(156.99)	(628.20)	-	-	-	-	-	-	-	(785.19)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(2,261,777,248.39)	(89,839,892.99)	18,709,533.13	-	-	-	3,903,434.69	(1,305,607.58)	-	(2,330,309,781.14)
Retirement Work in Process										
Electric..	13,605,672.01	-	-	14,675.52	(42,353.83)	(2,555,473.28)	6,432,503.29	(545,081.68)	(218,711.07)	16,691,230.96
	13,605,672.01	-	-	14,675.52	(42,353.83)	(2,555,473.28)	6,432,503.29	(545,081.68)	(218,711.07)	16,691,230.96
YTD ACTIVITY	(2,248,171,576.38)	(89,839,892.99)	18,709,533.13	14,675.52	(42,353.83)	(2,555,473.28)	10,335,937.98	(1,850,689.26)	(218,711.07)	(2,313,618,550.18)
Amortization										
Electric..	(13,755,205.98)	(3,498,810.87)	1,381,084.50	-	-	-	-	-	-	(15,872,932.35)
	(13,755,205.98)	(3,498,810.87)	1,381,084.50	-	-	-	-	-	-	(15,872,932.35)
Depreciation & Amortization Total										
Depreciation & Amortization Total...............	(2,261,926,782.36)	(93,338,703.86)	20,090,617.63	14,675.52	(42,353.83)	(2,555,473.28)	10,335,937.98	(1,850,689.26)	(218,711.07)	(2,329,491,482.53)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)...............	$ 4,234,854,513.03									$ 4,258,761,604.81

July 27, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of June 30, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues...................................	$ 133,025,751.99	$ -	$ 133,025,751.99
Rate Refunds...	-	-	-
Total Operating Revenues....................................	133,025,751.99	-	133,025,751.99
Fuel for Electric Generation.....................................	51,080,753.18	-	51,080,753.18
Power Purchased...	4,961,514.11	-	4,961,514.11
Other Operation Expenses.......................................	20,353,304.26	-	20,353,304.26
Maintenance..	9,885,118.94	-	9,885,118.94
Depreciation..	15,226,844.03	(0.05)	15,226,843.98
Amortization Expense...	602,329.81	-	602,329.81
Regulatory Credits...	(473,137.66)	-	(473,137.66)
Taxes			
Federal Income..	(16,089,366.68)	-	(16,089,366.68)
State Income..	(963,179.88)	-	(963,179.88)
Deferred Federal Income - Net..............................	23,593,701.47	50,404.86	23,644,106.33
Deferred State Income - Net..................................	2,074,513.77	9,192.37	2,083,706.14
Property and Other..	2,313,840.66	-	2,313,840.66
Loss (Gain) from Disposition of Allowances...........	-	-	-
Accretion Expense...	229,165.18	-	229,165.18
Total Operating Expenses.....................................	112,795,401.19	59,597.18	112,854,998.37
Net Operating Income...	20,230,350.80	(59,597.18)	20,170,753.62
Other Income Less Deductions			
Amortization of Investment Tax Credit.............	233,343.00	-	233,343.00
Other Income Less Deductions..........................	609,872.64	12,331.35	622,203.99
AFUDC - Equity...	3,787.83	-	3,787.83
Total Other Income Less Deductions....................	847,003.47	12,331.35	859,334.82
Income Before Interest Charges............................	21,077,354.27	(47,265.83)	21,030,088.44
Interest on Long-Term Debt....................................	5,087,278.50	(5,525.49)	5,081,753.01
Amortization of Debt Expense - Net........................	320,194.75	-	320,194.75
Other Interest Expenses...	618,531.83	-	618,531.83
AFUDC - Borrowed Funds......................................	(1,155.51)	-	(1,155.51)
Total Interest Charges...	6,024,849.57	(5,525.49)	6,019,324.08
Net Income..	$ 15,052,504.70	$ (41,740.34)	$ 15,010,764.36

Note: Purchase accounting is subject to change through October 31, 2011

July 27, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of June 30, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 771,232,868.59	$ -	$ 771,232,868.59
Rate Refunds	-	-	-
Total Operating Revenues	771,232,868.59	-	771,232,868.59
Fuel for Electric Generation	257,419,703.04	-	257,419,703.04
Power Purchased	57,694,127.77	-	57,694,127.77
Other Operation Expenses	114,921,100.45	31,612.30	114,952,712.75
Maintenance	63,263,719.43	-	63,263,719.43
Depreciation	89,737,522.42	-	89,737,522.42
Amortization Expense	3,498,810.87	-	3,498,810.87
Regulatory Credits	(2,850,407.05)	-	(2,850,407.05)
Taxes			
Federal Income	(3,174,533.87)	-	(3,174,533.87)
State Income	4,509,943.73	-	4,509,943.73
Deferred Federal Income - Net	48,680,498.78	506.89	48,681,005.67
Deferred State Income - Net	2,692,792.20	92.44	2,692,884.64
Property and Other	13,890,498.78	-	13,890,498.78
Loss (Gain) from Disposition of Allowances	(3,293.39)	-	(3,293.39)
Accretion Expense	1,361,583.68	-	1,361,583.68
Total Operating Expenses	651,642,066.84	32,211.63	651,674,278.47
Net Operating Income	119,590,801.75	(32,211.63)	119,558,590.12
Other Income Less Deductions			
Amortization of Investment Tax Credit	1,286,347.00	-	1,286,347.00
Other Income Less Deductions	694,209.56	996,781.16	1,690,990.72
AFUDC - Equity	14,145.38	-	14,145.38
Total Other Income Less Deductions	1,994,701.94	996,781.16	2,991,483.10
Income Before Interest Charges	121,585,503.69	964,569.53	122,550,073.22
Interest on Long-Term Debt	30,738,892.42	(33,152.95)	30,705,739.47
Amortization of Debt Expense - Net	1,803,028.70	-	1,803,028.70
Other Interest Expenses	2,922,826.23	-	2,922,826.23
AFUDC - Borrowed Funds	(4,300.33)	-	(4,300.33)
Total Interest Charges	35,460,447.02	(33,152.95)	35,427,294.07
Net Income	$ 86,125,056.67	$ 997,722.48	$ 87,122,779.15

Note: Purchase accounting is subject to change through October 31, 2011

July 27, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of June 30, 2011

Retained Earnings and Undistributed Earnings	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,441,543,639.79	$ 15,312,901.75	$ (1,402,591,387.21)	$ (14,757,702.19)	$ 38,952,252.58	$ 555,199.56
Add						
Net Income for Period..	15,052,504.70	-	(41,740.34)	-	15,010,764.36	-
Deductions:						
Common Dividends						
Common Stock Without Par Value..................	-	-	-	-	-	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	(139,383.00)	139,383.00	73,840.35	(73,840.35)	(65,542.65)	65,542.65
Balance at End of Period	$ 1,456,456,761.49	$ 15,452,284.75	$ (1,402,559,287.20)	$ (14,831,542.54)	$ 53,897,474.29	$ 620,742.21
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings................		15,452,284.75		(14,831,542.54)		620,742.21
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.........................		$ 6,010,938.77		$ (5,769,470.05)		$ 241,468.72

Note: Purchase accounting is subject to change through October 31, 2011.

July 27, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of June 30, 2011

Retained Earnings and Undistributed Earnings	Year to Date without Purchase Accounting: Retained Earnings	Year to Date without Purchase Accounting: Undistributed Subsidiary Earnings	Year to Date Purchase Accounting: Retained Earnings	Year to Date Purchase Accounting: Undistributed Subsidiary Earnings	Year to Date Combined: Retained Earnings	Year to Date Combined: Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,439,351,593.82	$ 14,432,395.75	$ (1,404,000,051.78)	$ (14,388,500.44)	$ 35,351,542.04	$ 43,895.31
Add						
Net Income for Period ……………………………	86,125,056.67	-	997,722.48	-	87,122,779.15	-
Deductions:						
Common Dividends						
Common Stock Without Par Value...................	(68,000,000.00)	-	-	-	(68,000,000.00)	-
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc………………………..…………	(1,019,889.00)	1,019,889.00	443,042.10	(443,042.10)	(576,846.90)	576,846.90
Balance at End of Period …...……………………………	$ 1,456,456,761.49	$ 15,452,284.75	$ (1,402,559,287.20)	$ (14,831,542.54)	$ 53,897,474.29	$ 620,742.21
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings…………		15,452,284.75		(14,831,542.54)		620,742.21
Statutory Tax Rate…...…………………………………		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary…...……………		$ 6,010,938.77		$ (5,769,470.05)		$ 241,468.72

Note: Purchase accounting is subject to change through October 31, 2011

July 27, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of June 30, 2011

Retained Earnings and Undistributed Earnings	Year Ended Current Month without Purchase Accounting: Retained Earnings	Year Ended Current Month without Purchase Accounting: Undistributed Subsidiary Earnings	Year Ended Current Month to Date Purchase Accounting: Retained Earnings	Year Ended Current Month to Date Purchase Accounting: Undistributed Subsidiary Earnings	Year Ended Current Month Combined: Retained Earnings	Year Ended Current Month Combined: Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,390,181,898.77	$ 12,466,582.75	$ -	$ -	$ 1,390,181,898.77	$ 12,466,582.75
Add						
Net Income for Period...	187,260,564.72	-	933,556.86	-	188,194,121.58	-
Purchase Accounting Deductions:	-	-	(1,404,083,566.85)	(14,240,819.75)	(1,404,083,566.85)	(14,240,819.75)
Deductions:						
Common Dividends						
Common Stock Without Par Value....................	(118,000,000.00)	-	-	-	(118,000,000.00)	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	(2,985,702.00)	2,985,702.00	590,722.79	(590,722.79)	(2,394,979.21)	2,394,979.21
Balance at End of Period	$ 1,456,456,761.49	$ 15,452,284.75	$ (1,402,559,287.20)	$ (14,831,542.54)	$ 53,897,474.29	$ 620,742.21

Deferred Taxes Related to Undistributed Subsidiary Earnings	Without Purchase Accounting	To Date Purchase Accounting	Combined
Balance of Undistributed Subsidiary Earnings................	15,452,284.75	(14,831,542.54)	620,742.21
Statutory Tax Rate...	38.9%	38.9%	38.9%
Deferred Taxes on Equity in Subsidiary..........................	$ 6,010,938.77	$ (5,769,470.05)	$ 241,468.72

Combined Balance of Retained Earnings	12 MONTHS 6/30/2011	12 MONTHS 6/30/2010
Retained Earnings at Beginning of Period........................	$ 1,402,648,481.52	$ 1,216,199,359.13
Net Income for Period	188,194,121.58	175,114,278.04
FIN 48 Adjustment...	-	-
Subtotal...	1,590,842,603.10	1,391,313,637.17
Deduct		
Purchase Accounting Adjustment...............................	1,418,324,386.60	-
Dividends on Common Stock.....................................	118,000,000.00	-
Retained Earnings at End of Period.................................	$ 54,518,216.50	$ 1,391,313,637.17

Note: Purchase accounting is subject to change through October 31, 2011

July 27, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of June 30, 2011

Assets	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 6,588,253,087.34	$ -	$ 6,588,253,087.34
Less Reserves for Depreciation and Amortization.....	2,329,491,482.53	-	2,329,491,482.53
Total..	4,258,761,604.81	-	4,258,761,604.81
Investments			
Electric Energy, Inc...	12,674,129.55	17,130,960.21	29,805,089.76
Ohio Valley Electric Corporation.............................	250,000.00	-	250,000.00
Nonutility Property - Less Reserve...........................	179,120.94	-	179,120.94
Special Funds...	-	-	-
Total..	13,103,250.49	17,130,960.21	30,234,210.70
Current and Accrued Assets			
Cash..	6,817,643.07	-	6,817,643.07
Special Deposits..	640,705.40	-	640,705.40
Temporary Cash Investments.................................	12,114.69	-	12,114.69
Accounts Receivable-Less Reserve........................	165,764,056.58	-	165,764,056.58
Accounts Receivable from Assoc Companies..........	5,001,224.57	-	5,001,224.57
Materials & Supplies-At Average Cost			
Fuel...	92,538,396.90	-	92,538,396.90
Plant Materials & Operating Supplies..................	33,129,391.71	-	33,129,391.71
Stores Expense..	9,723,255.58	-	9,723,255.58
Allowance Inventory..	512,525.39	-	512,525.39
Prepayments..	7,923,784.79	-	7,923,784.79
Miscellaneous Current & Accrued Assets..............	98,710.66	-	98,710.66
Total..	322,161,809.34	-	322,161,809.34
Deferred Debits and Other			
Unamortized Debt Expense......................................	21,814,142.64	(4,518,088.25)	17,296,054.39
Unamortized Loss on Bonds....................................	12,077,603.71	-	12,077,603.71
Accumulated Deferred Income Taxes.......................	76,681,026.30	69,181,824.41	145,862,850.71
Deferred Regulatory Assets.....................................	279,417,797.15	17,301,946.01	296,719,743.16
Other Deferred Debits..	44,251,239.15	163,944,198.28	208,195,437.43
Goodwill..	-	607,404,368.23	607,404,368.23
Total..	434,241,808.95	853,314,248.68	1,287,556,057.63
Total Assets..	$ 5,028,268,473.59	$ 870,445,208.89	$ 5,898,713,682.48

Note: Purchase accounting is subject to change through October 31, 2011

July 27, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of June 30, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Proprietary Capital			
Common Stock..	$ 308,139,977.56	$ -	$ 308,139,977.56
Less: Common Stock Expense......................................	321,288.87	-	321,288.87
Paid-In Capital..	315,858,083.00	2,032,588,750.94	2,348,446,833.94
Other Comprehensive Income.....................................	(2,489,186.63)	1,990,823.26	(498,363.37)
Retained Earnings...	1,456,456,761.49	(1,402,559,287.20)	53,897,474.29
Unappropriated Undistributed Subsidiary Earnings....	15,452,284.75	(14,831,542.54)	620,742.21
Total Proprietary Capital..	2,093,096,631.30	617,188,744.46	2,710,285,375.76
Pollution Control Bonds - Net of Reacquired Bonds...	350,779,405.00	1,117,251.07	351,896,656.07
First Mortgage Bonds...	1,489,494,531.25	-	1,489,494,531.25
Total Long-Term Debt...	1,840,273,936.25	1,117,251.07	1,841,391,187.32
Total Capitalization..	3,933,370,567.55	618,305,995.53	4,551,676,563.08
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Accounts Payable...	76,456,703.25	-	76,456,703.25
Accounts Payable to Associated Companies................	26,344,328.96	-	26,344,328.96
Customer Deposits...	23,299,986.50	-	23,299,986.50
Taxes Accrued..	11,293,906.28	-	11,293,906.28
Interest Accrued...	10,004,371.62	-	10,004,371.62
Dividends Declared..	-	-	-
Miscellaneous Current and Accrued Liabilities...........	21,000,490.72	-	21,000,490.72
Total..	168,399,787.33	-	168,399,787.33
Deferred Credits and Other			
Accumulated Deferred Income Taxes..........................	491,559,670.98	75,411,157.32	566,970,828.30
Investment Tax Credit..	102,807,822.32	-	102,807,822.32
Regulatory Liabilities...	113,430,635.84	163,944,198.28	277,374,834.12
Customer Advances for Construction..........................	3,173,808.69	-	3,173,808.69
Asset Retirement Obligations......................................	55,284,494.83	-	55,284,494.83
Other Deferred Credits...	22,009,407.47	12,783,857.76	34,793,265.23
Miscellaneous Long-Term Liabilities..........................	2,805,389.46	-	2,805,389.46
Accum Provision for Postretirement Benefits.............	135,426,889.12	-	135,426,889.12
Total..	926,498,118.71	252,139,213.36	1,178,637,332.07
Total Liabilities and Stockholders' Equity.........................	$ 5,028,268,473.59	$ 870,445,208.89	$ 5,898,713,682.48

Note: Purchase accounting is subject to change through October 31, 2011

July 27, 2011

KENTUCKY UTILITIES COMPANY

Financial Reports

May 31, 2011

Index
Financial and Operating Reports

Kentucky Utilities Company
May 31, 2011

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2011 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows, unless otherwise noted.

Kentucky Utilities Company
Comparative Statement of Income
May 31, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 125,468,971.21	$ 114,765,215.94	$ 10,703,755.27	9.33
Rate Refunds	-	987,769.21	(987,769.21)	(100.00)
Total Operating Revenues	125,468,971.21	115,752,985.15	9,715,986.06	8.39
Fuel for Electric Generation	43,006,003.01	37,646,251.80	5,359,751.21	14.24
Power Purchased	7,382,551.12	14,277,922.94	(6,895,371.82)	(48.29)
Other Operation Expenses	19,445,893.91	18,804,792.06	641,101.85	3.41
Maintenance	12,995,142.09	9,374,707.66	3,620,434.43	38.62
Depreciation	15,163,173.93	10,826,668.45	4,336,505.48	40.05
Amortization Expense	596,216.66	528,881.04	67,335.62	12.73
Regulatory Credits	(472,173.53)	(208,974.98)	(263,198.55)	(125.95)
Taxes				
Federal Income	3,800,442.10	5,285,445.63	(1,485,003.53)	(28.10)
State Income	2,296,685.49	963,911.06	1,332,774.43	138.27
Deferred Federal Income - Net	2,955,121.48	-	2,955,121.48	100.00
Deferred State Income - Net	(1,158,530.40)	-	(1,158,530.40)	(100.00)
Property and Other	2,336,418.31	1,647,802.43	688,615.88	41.79
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	-	-	-	-
Accretion Expense	228,200.96	184,230.08	43,970.88	23.87
Total Operating Expenses	108,575,145.13	99,331,638.17	9,243,506.96	9.31
Net Operating Income	16,893,826.08	16,421,346.98	472,479.10	2.88
Other Income Less Deductions				
Amortization of Investment Tax Credit	233,343.00	5,925.00	227,418.00	3,838.28
Other Income Less Deductions	(149,931.87)	(584,868.10)	434,936.23	74.36
AFUDC - Equity	2,838.02	(11,506.57)	14,344.59	124.66
Total Other Income Less Deductions	86,249.15	(590,449.67)	676,698.82	114.61
Income Before Interest Charges	16,980,075.23	15,830,897.31	1,149,177.92	7.26
Interest on Long-Term Debt	5,115,872.14	6,348,561.97	(1,232,689.83)	(19.42)
Amortization of Debt Expense - Net	317,143.66	68,396.91	248,746.75	363.68
Other Interest Expenses	363,856.49	269,860.83	93,995.66	34.83
AFUDC - Borrowed Funds	(863.05)	(81,467.35)	80,604.30	98.94
Total Interest Charges	5,796,009.24	6,605,352.36	(809,343.12)	(12.25)
Net Income	$ 11,184,065.99	$ 9,225,544.95	$ 1,958,521.04	21.23

June 21, 2011

Kentucky Utilities Company
Comparative Statement of Income
May 31, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues......................................	$ 638,207,116.60	$ 599,036,596.74	$ 39,170,519.86	6.54
Rate Refunds...	-	-	-	-
Total Operating Revenues.......................................	638,207,116.60	599,036,596.74	39,170,519.86	6.54
Fuel for Electric Generation.......................................	206,338,949.86	191,557,086.28	14,781,863.58	7.72
Power Purchased..	52,732,613.66	83,268,872.32	(30,536,258.66)	(36.67)
Other Operation Expenses...	94,567,796.19	86,283,868.48	8,283,927.71	9.60
Maintenance...	53,378,600.49	41,391,176.81	11,987,423.68	28.96
Depreciation...	74,510,678.39	53,961,397.00	20,549,281.39	38.08
Amortization Expense...	2,896,481.06	2,776,313.55	120,167.51	4.33
Regulatory Credits..	(2,377,269.39)	(1,035,466.89)	(1,341,802.50)	(129.58)
Taxes				
Federal Income..	12,914,832.81	25,084,462.97	(12,169,630.16)	(48.51)
State Income..	5,473,123.61	4,406,003.45	1,067,120.16	24.22
Deferred Federal Income - Net................................	25,086,797.31	6,735,680.77	18,351,116.54	272.45
Deferred State Income - Net...................................	618,278.43	1,330,268.67	(711,990.24)	(53.52)
Property and Other...	11,576,658.12	8,407,220.40	3,169,437.72	37.70
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances............	(3,293.39)	(44,023.81)	40,730.42	92.52
Accretion Expense..	1,132,418.50	911,628.43	220,790.07	24.22
Total Operating Expenses......................................	538,846,665.65	505,034,488.43	33,812,177.22	6.70
Net Operating Income...	99,360,450.95	94,002,108.31	5,358,342.64	5.70
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	1,053,004.00	29,625.00	1,023,379.00	3,454.44
Other Income Less Deductions...........................	84,336.92	1,093,069.55	(1,008,732.63)	(92.28)
AFUDC - Equity...	10,357.55	(59,479.57)	69,837.12	117.41
Total Other Income Less Deductions......................	1,147,698.47	1,063,214.98	84,483.49	7.95
Income Before Interest Charges.............................	100,508,149.42	95,065,323.29	5,442,826.13	5.73
Interest on Long-Term Debt......................................	25,651,613.92	31,828,309.49	(6,176,695.57)	(19.41)
Amortization of Debt Expense - Net.........................	1,482,833.95	341,978.88	1,140,855.07	333.60
Other Interest Expenses..	2,304,294.40	1,440,816.90	863,477.50	59.93
AFUDC - Borrowed Funds.......................................	(3,144.82)	(400,915.68)	397,770.86	99.22
Total Interest Charges..	29,435,597.45	33,210,189.59	(3,774,592.14)	(11.37)
Net Income..	$ 71,072,551.97	$ 61,855,133.70	$ 9,217,418.27	14.90

June 21, 2011

Kentucky Utilities Company
Comparative Statement of Income
May 31, 2011

	Year Ended Current Month			
	This Year	Last Year	Increase or Decrease	
	Amount	Amount	Amount	%
Electric Operating Revenues.....................................	$ 1,551,512,615.78	$ 1,391,380,423.94	$ 160,132,191.84	11.51
Rate Refunds..	(632,383.92)	(469,230.79)	(163,153.13)	(34.77)
Total Operating Revenues......................................	1,550,880,231.86	1,390,911,193.15	159,969,038.71	11.50
Fuel for Electric Generation......................................	510,866,051.71	451,036,624.87	59,829,426.84	13.26
Power Purchased...	144,085,678.61	190,775,405.34	(46,689,726.73)	(24.47)
Other Operation Expenses..	224,931,155.48	202,490,232.85	22,440,922.63	11.08
Maintenance..	119,801,408.48	50,694,550.75	69,106,857.73	136.32
Depreciation..	159,831,322.08	128,750,149.26	31,081,172.82	24.14
Amortization Expense...	6,723,631.43	6,671,633.12	51,998.31	0.78
Regulatory Credits..	(6,491,359.85)	(2,454,365.17)	(4,036,994.68)	(164.48)
Taxes				
Federal Income...	49,489,819.12	18,740,410.66	30,749,408.46	164.08
State Income...	13,823,512.67	4,569,913.76	9,253,598.91	202.49
Deferred Federal Income - Net...............................	40,626,568.29	48,228,528.07	(7,601,959.78)	(15.76)
Deferred State Income - Net...................................	2,599,047.94	9,179,838.46	(6,580,790.52)	(71.69)
Property and Other...	23,062,916.69	19,631,221.87	3,431,694.82	17.48
Investment Tax Credit..	-	16,062,341.26	(16,062,341.26)	(100.00)
Loss (Gain) from Disposition of Allowances...........	(16,020.32)	(44,023.81)	28,003.49	63.61
Accretion Expense..	3,719,695.01	2,154,522.01	1,565,173.00	72.65
Total Operating Expenses......................................	1,293,053,427.34	1,146,486,983.30	146,566,444.04	12.78
Net Operating Income...	257,826,804.52	244,424,209.85	13,402,594.67	5.48
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	1,094,479.00	111,239.25	983,239.75	883.90
Other Income Less Deductions...........................	49,181.29	2,085,779.77	(2,036,598.48)	(97.64)
AFUDC - Equity...	590,989.16	1,423,095.08	(832,105.92)	(58.47)
Total Other Income Less Deductions......................	1,734,649.45	3,620,114.10	(1,885,464.65)	(52.08)
Income Before Interest Charges.............................	259,561,453.97	248,044,323.95	11,517,130.02	4.64
Interest on Long-Term Debt......................................	68,267,746.65	74,787,412.46	(6,519,665.81)	(8.72)
Amortization of Debt Expense - Net.........................	2,329,796.98	820,466.49	1,509,330.49	183.96
Other Interest Expenses..	4,822,900.47	3,416,354.00	1,406,546.47	41.17
AFUDC - Borrowed Funds.......................................	(570,826.07)	(1,029,980.96)	459,154.89	44.58
Total Interest Charges..	74,849,618.03	77,994,251.99	(3,144,633.96)	(4.03)
Net Income..	$ 184,711,835.94	$ 170,050,071.96	$ 14,661,763.98	8.62

June 21, 2011

Kentucky Utilities Company
Analysis of Retained Earnings
May 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
Retained Earnings and Undistributed Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings	Total Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period	$ 1,467,482,992.80	$ 15,189,482.75	$ 1,439,351,593.82	$ 14,432,395.75	$ 1,377,532,218.85	$ 12,612,486.75
Add:						
Net Income for Period	11,184,065.99	-	71,072,551.97	-	184,711,835.94	-
Deduct:						
Common Dividends						
Common Stock Without Par Value	(37,000,000.00)	-	(68,000,000.00)	-	(118,000,000.00)	-
EE Inc.	(123,419.00)	123,419.00	(880,506.00)	880,506.00	(2,700,415.00)	2,700,415.00
Balance at End of Period	$ 1,441,543,639.79	$ 15,312,901.75	$ 1,441,543,639.79	$ 15,312,901.75	$ 1,441,543,639.79	$ 15,312,901.75
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings		15,312,901.75		15,312,901.75		15,312,901.75
Statutory Tax Rate		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary		$ 5,956,718.78		$ 5,956,718.78		$ 5,956,718.78

June 21, 2011

Kentucky Utilities Company
Comparative Balance Sheets as of May 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,563,741,531.29	$ 6,252,343,935.72
Less: Reserves for Depreciation and Amortization	2,317,912,522.05	2,207,354,724.21
Total	4,245,829,009.24	4,044,989,211.51
Investments		
Electric Energy, Inc.	12,528,864.55	13,908,286.75
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	179,120.94	179,120.94
Total	12,957,985.49	14,337,407.69
Current and Accrued Assets		
Cash	36,897,070.19	2,499,081.12
Special Deposits	823,713.19	-
Temporary Cash Investments	10,792.75	269.25
Accounts Receivable-Less Reserve	152,810,722.21	160,058,354.14
Accounts Receivable from Associated Companies	-	2,468.15
Materials and Supplies-At Average Cost		
Fuel	96,484,082.93	116,481,379.35
Plant Materials and Operating Supplies	33,123,080.35	31,473,036.44
Stores Expense	9,417,290.34	8,189,380.16
Emission Allowances	523,516.78	741,375.68
Prepayments	7,342,581.45	4,994,279.87
Miscellaneous Current and Accrued Assets	103,768.46	176,206.41
Total	337,536,618.65	324,615,830.57
Deferred Debits and Other		
Unamortized Debt Expense	21,884,073.12	4,752,815.86
Unamortized Loss on Bonds	12,128,018.10	12,732,990.78
Accumulated Deferred Income Taxes	88,931,970.66	46,235,144.29
Deferred Regulatory Assets	280,194,551.01	232,739,610.33
Other Deferred Debits	43,422,416.86	42,185,648.47
Total	446,561,029.75	338,646,209.73
Total Assets	$ 5,042,884,643.13	$ 4,722,588,659.50

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	315,858,083.00	315,858,083.00
Other Comprehensive Income	(2,488,203.95)	-
Retained Earnings	1,441,543,639.79	1,377,532,218.85
Unappropriated Undistributed Subsidiary Earnings	15,312,901.75	12,612,486.75
Total Proprietary Capital	2,078,045,109.28	2,013,821,477.29
Pollution Control Bonds	350,779,405.00	350,779,405.00
First Mortgage Bonds	1,489,441,593.75	-
LT Notes Payable to Associated Companies	-	1,298,000,000.00
Total Long-Term Debt	1,840,220,998.75	1,648,779,405.00
Total Capitalization	3,918,266,108.03	3,662,600,882.29
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	104,424,954.00
Accounts Payable	77,334,267.91	97,566,739.31
Accounts Payable to Associated Companies	31,038,474.94	45,515,892.71
Customer Deposits	23,248,184.46	22,806,864.06
Taxes Accrued	21,639,563.75	22,666,023.85
Interest Accrued	6,773,699.99	1,380,452.39
Dividends Declared	37,000,000.00	-
Miscellaneous Current and Accrued Liabilities	17,504,558.93	15,458,897.94
Total	214,538,749.98	309,819,824.26
Deferred Credits and Other		
Accumulated Deferred Income Taxes	477,326,620.69	387,794,312.81
Investment Tax Credit	103,041,165.32	104,135,644.32
Regulatory Liabilities	114,137,068.78	44,982,832.89
Customer Advances for Construction	2,772,266.47	2,934,393.42
Asset Retirement Obligations	55,055,329.65	35,262,099.84
Other Deferred Credits	19,921,934.09	21,611,540.71
Miscellaneous Long-Term Liabilities	2,388,318.25	2,628,519.48
Accum Provision for Postretirement Benefits	135,437,081.87	150,818,609.48
Total	910,079,785.12	750,167,952.95
Total Liabilities and Stockholders Equity	$ 5,042,884,643.13	$ 4,722,588,659.50

June 21, 2011

Kentucky Utilities Company
Statement of Capitalization and Short-Term Debt
May 31, 2011

	Authorized Shares	Issued and Outstanding Shares	Issued and Outstanding Amount	Percent of Total Capital
Proprietary Capital				
Common Stock - Without Par..	80,000,000	37,817,878	$ 308,139,977.56	
Less: Common Stock Expense..			321,288.87	
Paid-In Capital..			315,858,083.00	
Other Comprehensive Income..			(2,488,203.95)	
Retained Earnings..			1,441,543,639.79	
Unappropriated Undistributed Subsidiary Earnings.............			15,312,901.75	
Total Proprietary Capital...			2,078,045,109.28	53.04
Long-Term Debt				
Pollution Control Bonds				
Mercer County 2000 Series A due 05/01/23 Var%..........			12,900,000.00	
Carroll County 2002 Series A due 02/01/32 Var%..........			20,930,000.00	
Carroll County 2002 Series B due 02/01/32 Var%..........			2,400,000.00	
Carroll County 2002 Series C due 10/01/32 Var%..........			96,000,000.00	
Mercer County 2002 Series A due 02/01/32 Var%..........			7,400,000.00	
Muhlenburg County 2002 Series A due 02/01/32 Var%...			2,400,000.00	
Carroll County 2004 Series A due 10/01/34 Var%..........			50,000,000.00	
Carroll County 2006 Series B due 10/01/34 Var%..........			54,000,000.00	
Carroll County 2007 Series A due 02/01/26 5.75%.........			17,875,000.00	
Trimble County 2007 Series A due 03/01/37 6.00%........			8,927,000.00	
Carroll County 2008 Series A due 02/01/32 Var%..........			77,947,405.00	
Total Pollution Control Bonds..			350,779,405.00	8.95
First Mortgage Bonds				
First Mortgage Bond Due 11/01/15 1.625%......................			250,000,000.00	
First Mortgage Bond Due 11/01/20 3.250%.....................			500,000,000.00	
First Mortgage Bond Due 11/01/40 5.125%.....................			750,000,000.00	
Total First Mortgage Bonds..			1,500,000,000.00	38.28
Less: First Mortgage Bonds Debt Discount				
First Mortgage Bond Due 11/01/15 1.625%......................			(780,208.33)	
First Mortgage Bond Due 11/01/20 3.250%.....................			(1,787,625.00)	
First Mortgage Bond Due 11/01/40 5.125%.....................			(7,990,572.92)	
			(10,558,406.25)	(0.27)
Total First Mortgage Bonds - Net of Debt Discount............			1,489,441,593.75	38.01
Total Capitalization...			$ 3,918,266,108.03	100.00

June 21, 2011

Kentucky Utilities Company
Summary Trial Balance
May 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 6,563,741,531.29	$ 6,563,741,531.29
Reserves for Depreciation and Amortization		(2,317,912,522.05)
Depreciation of Plant	(2,302,641,919.51)	
Amortization of Plant	(15,270,602.54)	
Investments		12,957,985.49
Electric Energy, Inc	12,528,864.55	
Ohio Valley Electric Corporation	250,000.00	
Nonutility Property Reserve	179,120.94	
Cash	36,897,070.19	36,897,070.19
Special Deposits		823,713.19
MAN Margin Call	823,713.19	
Temporary Cash Investments	10,792.75	10,792.75
Accounts Receivable - Less Reserve		152,810,722.21
Unbilled Revenues	75,319,000.00	
Customers - Active	66,392,723.55	
Bechtel Liquidated Damages	9,969,285.60	
IMPA	1,841,867.12	
IMEA	1,732,335.43	
Transmission Sales	936,652.86	
Damage Claims	352,953.38	
IMEA/IMPA Net Portion of Bechtel Liquidated damages	(999,540.00)	
Other	5,365,711.97	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	2,788,716.79	
Bechtel Reserve	(5,971,125.60)	
Reserve	(2,023,386.00)	
Accrual	(2,299,894.36)	
Recoveries	(488,541.43)	
A/R Miscellaneous	(106,037.10)	
Fuel		96,484,082.93
Coal 1,604,174.91 Tons @ $55.66 MMBtu 37,019,254.34 @ 241.19¢	89,285,472.85	
Fuel Oil 2,888,412.00 Gallons @ 247.72¢	7,155,240.34	
Gas Pipeline 13,197.80 Mcf @ $3.29	43,369.74	
Plant Materials and Operating Supplies		33,123,080.35
Regular Materials and Supplies	32,433,150.37	
Limestone 63,731.79 Tons @ $10.83	689,929.96	
Other Reagents	0.02	
Stores Expense Undistributed	9,417,290.34	9,417,290.34

June 21, 2011

Kentucky Utilities Company
Summary Trial Balance
May 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Emission Allowances	$ 523,516.78	$ 523,516.78
Prepayments		7,342,581.45
Insurance	5,433,155.23	
Lease	684,406.62	
Taxes	157,659.42	
Risk Management and Workers Compensation	75,000.00	
Other	992,360.18	
Miscellaneous Current Assets		103,768.46
Derivative Asset - Non-Hedging	103,768.46	
Unamortized Debt Expense		21,884,073.12
Carroll County 2002 Series A due 02/01/32 Var%	84,738.34	
Carroll County 2002 Series B due 02/01/32 Var%	58,895.62	
Carroll County 2002 Series C due 10/01/32 Var%	1,571,370.53	
Mercer County 2002 Series A due 02/01/32 Var%	23,653.40	
Muhlenburg County 2002 Series A due 02/01/32 Var%	65,562.11	
Carroll County 2006 Series B due 10/01/34 Var%	1,118,134.12	
Carroll County 2007 Series A due 02/01/26 5.75%	489,017.82	
Trimble County 2007 Series A due 03/01/37 6.00%	413,845.71	
Carroll County 2008 Series A due 02/01/32 Var%	710,926.57	
First Mortgage Bond due 11/01/15 1.625%	1,919,642.19	
First Mortgage Bond due 11/01/20 3.250%	3,825,382.76	
First Mortgage Bond due 11/01/40 5.125%	7,225,987.24	
Revolving Credit Agreement	4,376,916.71	
Unamortized Loss on Bonds		12,128,018.10
Refinanced and Called Bonds	12,128,018.10	
Accumulated Deferred Income Taxes		88,931,970.66
Federal	75,297,187.49	
State	13,634,783.17	
Regulatory Assets		280,194,551.01
Pension and Postretirement Benefits	117,274,368.11	
SFAS 109 - Deferred Taxes	77,709,402.11	
2009 Winter Storm	52,467,028.62	
Virginia Mountain Snowstorm	6,041,670.12	
FERC Jurisdictional Pension Expense	5,267,043.61	
VA Fuel Component Non-Current	5,165,000.00	
MISO Exit Fee	4,543,180.06	
Asset Retirement Obligations	3,869,722.83	
Fuel Adjustment Clause	2,139,000.00	
2008 Wind Storm	2,012,556.65	
Rate Case Expenses	1,800,385.25	
EKPC FERC Transmission Cost	920,416.92	
KCCS Funding	729,885.40	
CMRG Funding	221,953.30	
General Management Audit	32,938.03	
Other Deferred Debits	43,422,416.86	43,422,416.86
Total Assets	$ 5,042,884,643.13	$ 5,042,884,643.13

June 21, 2011

Kentucky Utilities Company
Summary Trial Balance
May 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 2,078,045,109.28
Common Stock	308,139,977.56	
Less: Common Stock Expense	321,288.87	
Paid-In Capital	315,858,083.00	
Other Comprehensive Income	(2,488,203.95)	
Retained Earnings	1,441,543,639.79	
Unappropriated Undistributed Subsidiary Earnings	15,312,901.75	
Bonds		1,840,220,998.75
Pollution Control Bonds - Net of Reacquired Bonds	350,779,405.00	
First Mortgage Bonds	1,489,441,593.75	
Accounts Payable		77,334,267.91
Regular	75,326,124.16	
Salaries and Wages Accrued	1,966,693.91	
Employee Withholdings Payable	41,449.84	
Accounts Payable to Associated Companies		31,038,474.94
LG&E - KU Energy Services/Louisville Gas and Electric Company	31,038,474.94	
Customers' Deposits	23,248,184.46	23,248,184.46
Taxes Accrued	21,639,563.75	21,639,563.75
Interest Accrued		6,773,699.99
Mercer County 2000 Series A due 05/01/23 Var%	2,438.63	
Carroll County 2002 Series A due 02/01/32 Var%	14,622.34	
Carroll County 2002 Series B due 02/01/32 Var%	315.62	
Carroll County 2002 Series C due 10/01/32 Var%	8,288.00	
Mercer County 2002 Series A due 02/01/32 Var%	973.15	
Muhlenburg County 2002 Series A due 02/01/32 Var%	315.62	
Carroll County 2004 Series A due 10/01/34 Var%	10,315.07	
Carroll County 2006 Series B due 10/01/34 Var%	11,421.37	
Carroll County 2007 Series A due 02/01/26 5.75%	513,906.25	
Trimble County 2007 Series A due 03/01/37 6.00%	267,810.00	
Carroll County 2008 Series A due 02/01/32 Var%	16,230.14	
First Mortgage Bond due 11/01/15 1.625%	338,541.67	
First Mortgage Bond due 11/01/20 3.250%	1,354,166.67	
First Mortgage Bond due 11/01/40 5.125%	3,203,125.00	
Customers' Deposits	1,006,979.31	
Other	24,251.15	
Dividends Declared		37,000,000.00
Dividend Payable to LG&E and KU Energy LLC	37,000,000.00	

June 21, 2011

Kentucky Utilities Company
Summary Trial Balance
May 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Miscellaneous Current and Accrued Liabilities		$ 17,504,558.93
Vacation Pay Accrued	6,672,878.07	
Tax Collections Payable	3,706,905.84	
Franchise Fee Payable	3,178,083.20	
Customer Overpayments	3,010,763.99	
Derivative Liabilities - Non-Hedging	561,970.03	
Home Energy Assistance	297,216.39	
Escheated Deposits	(200.91)	
Other	76,942.32	
Accumulated Deferred Income Taxes		477,326,620.69
Federal	414,005,782.50	
State	63,320,838.19	
Investment Tax Credit		103,041,165.32
Advanced Coal Credit	100,226,619.00	
Job Development Credit	2,814,546.32	
Regulatory Liabilities		114,137,068.78
Deferred Taxes		
Federal	63,480,872.07	
State	19,881,724.59	
Postretirement Benefits	9,787,090.00	
Environmental Cost Recovery	8,071,511.15	
DSM Cost Recovery	5,783,230.00	
Asset Retirement Obligations	4,481,079.59	
Spare Parts	1,825,456.64	
MISO Schedule 10 Charges	826,104.74	
Customers' Advances for Construction		2,772,266.47
Line Extensions	2,374,712.79	
Customer Advances	73,585.70	
Other	323,967.98	
Asset Retirement Obligations	55,055,329.65	55,055,329.65
Other Deferred Credits	19,921,934.09	19,921,934.09
Miscellaneous Long-Term Liabilities		2,388,318.25
Workers' Compensation	2,384,017.09	
Long-Term Derivative Liabilities-SFAS 133	4,301.16	
Accumulated Provision for Benefits		135,437,081.87
Pension Payable	70,301,999.50	
Postretirement Benefits - SFAS 106	65,684,171.72	
Post Employment Benefits Payable	5,554,516.00	
Post Employment Medicare Subsidy	(382,793.62)	
Medicare Subsidy - SFAS 106	(5,720,811.73)	
Total Liabilities and Stockholders Equity	$ 5,042,884,643.13	$ 5,042,884,643.13

June 21, 2011

Kentucky Utilities Company
Statement of Cash Flows
May 31, 2011

	Year to Date	
	2011	2010
Cash Flows from Operating Activities		
Net income	$ 71,072,551.97	$ 61,855,133.70
Items not requiring (providing) cash currently:		
Depreciation	74,510,678.39	53,961,397.00
Amortization	2,896,481.06	2,776,313.55
Deferred income taxes - net	26,328,156.46	8,196,996.85
Investment Tax Credit	(1,082,627.00)	-
Gain on disposal of assets	86,891.03	(1,825.45)
Other	(11,459,152.28)	9,357,223.06
Change in receivables	49,586,354.81	22,087,385.80
Change in inventory	(2,710,782.78)	(20,449,082.73)
Change in allowance inventory	43,062.22	233,700.22
Change in payables and accrued expenses	(6,422,033.09)	(20,392,444.18)
Change in regulatory assets	(65,273,418.92)	20,932,138.72
Change in regulatory liabilities	59,024,438.38	738,389.49
Change in other deferred debits	(9,089,993.62)	(2,291,714.77)
Change in other deferred credits	11,637,874.02	11,734,742.85
Other	(39,063,324.16)	(14,035,770.41)
Less: Allowance for other funds used during construction	(7,212.73)	(341,436.11)
Less: Undistributed earnings of subsidiary company	(880,506.00)	(1,941,118.00)
Net cash provided (used) by operating activities	159,197,437.76	132,420,029.59
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(77,314,102.07)	(158,318,615.07)
Less: Allowance for other funds used during construction	7,212.73	341,436.11
Proceeds received from sales of property	(74,040.96)	-
Change in derivatives	(108,084.35)	(65,342.79)
Change in restricted cash	(368,250.50)	-
Other	(4,695,135.28)	-
Net cash provided (used) by investing activities	(82,552,400.43)	(158,042,521.75)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(1,636,621.25)	(514.80)
Net change in short-term debt	(10,434,000.00)	26,450,000.00
Dividends on common stock	(31,000,000.00)	-
Net cash provided (used) by financing activities	(43,070,621.25)	26,449,485.20
Net Increase (Decrease) in Cash and Cash Equivalents	33,574,416.08	826,993.04
Cash and Cash Equivalents at Beginning of Period	3,333,446.86	1,672,357.33
Cash and Cash Equivalents at End of Period	$ 36,907,862.94	$ 2,499,350.37

June 21, 2011

Kentucky Utilities Company
Analysis of Interest Charges
May 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Interest on Long-Term Debt						
Loan Agreement - Pollution Control Bonds						
Mercer County 2000 Series A due 05/01/23 Var%................	$ 2,473.97	$ 3,541.32	$ 13,627.64	$ 15,285.62	$ 40,551.45	$ 46,567.25
Carroll County 2002 Series A due 02/01/32 Var%................	15,998.56	10,665.70	100,286.26	66,603.29	182,113.97	202,619.60
Carroll County 2002 Series B due 02/01/32 Var%................	1,959.46	1,223.01	11,294.33	7,637.26	20,677.34	23,233.96
Carroll County 2002 Series C due 10/01/32 Var%................	21,978.67	49,848.00	135,098.76	352,775.96	470,122.76	525,037.28
Mercer County 2002 Series A due 02/01/32 Var%................	6,041.65	3,770.96	33,644.67	23,548.23	62,575.63	71,638.09
Muhlenburg County 2002 Series A due 02/01/32 Var%........	1,959.46	1,223.01	10,911.82	7,637.26	20,294.83	23,233.96
Carroll County 2004 Series A due 10/01/34 Var%................	10,698.63	14,178.08	59,109.48	57,465.75	151,945.10	152,849.32
Carroll County 2006 Series B due 10/01/34 Var%................	11,835.62	15,253.15	64,873.97	66,900.83	164,441.09	195,583.58
Carroll County 2007 Series A due 02/01/26 5.75%..............	85,651.04	85,651.04	428,255.21	428,255.21	1,027,812.50	1,027,812.50
Trimble County 2007 Series A due 03/01/37 6.00%.............	44,635.00	44,635.00	223,175.00	223,175.00	535,620.00	535,620.00
Carroll County 2008 Series A due 02/01/32 Var%................	16,806.74	22,060.18	92,170.12	96,462.57	235,935.03	279,559.97
Interest Rate Swaps..	-	-	-	-	-	-
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/01/15 1.625%...........................	338,541.67	-	1,692,708.33	-	2,200,520.84	-
First Mortgage Bond due 11/01/20 3.250%...........................	1,354,166.67	-	6,770,833.33	-	8,802,083.34	-
First Mortgage Bond due 11/01/40 5.125%...........................	3,203,125.00	-	16,015,625.00	-	20,820,312.50	-
Fidelia/PPL..	-	6,096,512.52	-	30,482,562.51	33,532,740.27	71,703,656.95
Total..	5,115,872.14	6,348,561.97	25,651,613.92	31,828,309.49	68,267,746.65	74,787,412.46
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense...................................	266,729.27	18,012.50	1,230,762.00	90,062.11	1,724,824.30	215,965.89
Amortization of Loss on Reacquired Debt................................	50,414.39	50,384.41	252,071.95	251,916.77	604,972.68	604,500.60
Total..	317,143.66	68,396.91	1,482,833.95	341,978.88	2,329,796.98	820,466.49
Other Interest Charges						
Customers' Deposits..	110,385.54	107,577.21	535,968.42	606,589.95	1,292,948.34	1,242,639.82
Other Tax Deficiencies...	-	-	(84,914.00)	572.00	2,155.07	572.00
Interest on DSM Cost Recovery...	1,777.13	609.78	2,022.00	11,339.50	9,063.19	68,978.11
Interest on Debt to Associated Companies.................................	219.70	9,995.94	4,416.48	36,753.31	94,706.58	73,261.46
AFUDC Borrowed Funds..	(863.05)	(81,467.35)	(3,144.82)	(400,915.68)	(570,826.07)	(1,029,980.96)
Other Interest Expense..	251,474.12	151,677.90	1,846,801.50	785,562.14	3,424,027.29	2,030,902.61
Total..	362,993.44	188,393.48	2,301,149.58	1,039,901.22	4,252,074.40	2,386,373.04
Total Interest..	$ 5,796,009.24	$ 6,605,352.36	$ 29,435,597.45	$ 33,210,189.59	$ 74,849,618.03	$ 77,994,251.99

June 21, 2011

Kentucky Utilities Company
Analysis of Taxes Charged and Accrued
May 31, 2011

Kind of Taxes	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year
Taxes Charged to Accounts 408.1 and 409.1...........				
Property Taxes..	$ 1,498,895.77	$ 908,194.01	$ 7,475,951.77	$ 4,540,970.05
Unemployment..	4,115.60	4,301.64	78,135.72	80,379.69
FICA..	672,501.30	575,966.75	3,199,464.82	2,970,143.04
Public Service Commission Fee..............................	157,659.37	156,290.97	788,296.85	781,454.85
Federal Income..	3,800,442.10	5,285,445.63	12,914,832.81	25,084,462.97
State Income..	2,296,685.49	963,911.06	5,473,123.61	4,406,003.45
Miscellaneous..	3,246.27	3,049.06	34,808.96	34,272.77
Total Charged to Operating Expense..........	8,433,545.90	7,897,159.12	29,964,614.54	37,897,686.82
Taxes Charged to Other Accounts..........................	484,560.94	(21,244.04)	2,142,396.38	917,571.89
Taxes Accrued on Intercompany Accounts............	(309,763.32)	(249,320.13)	(1,816,100.87)	(1,321,071.08)
Total Taxes Charged.................................	$ 8,608,343.52	$ 7,626,594.95	$ 30,290,910.05	$ 37,494,187.63

Analysis of Taxes Accrued - Account 236

Kind of Taxes	Taxes Accrued At Beginning Of Year	Accruals To Date This Year	Payments To Date This Year	Taxes Accrued At End Of Month
Property Taxes..	$ 8,399,528.00	$ 7,476,786.77	$ 8,099,668.08	$ 7,776,646.69
Unemployment..	75,728.12	58,578.82	133,776.50	530.44
FICA..	639,011.24	2,563,568.28	2,877,386.98	325,192.54
Federal Income..	12,876,014.95	12,771,167.42	18,813,291.00	6,833,891.37
State Income..	2,021,178.48	5,897,806.23	1,477,172.00	6,441,812.71
Kentucky Sales and Use Tax..................................	581,659.33	1,416,642.62	1,748,246.02	250,055.93
Miscellaneous..	21,662.86	106,359.91	116,588.70	11,434.07
Totals..	$ 24,614,782.98	$ 30,290,910.05	$ 33,266,129.28	$ 21,639,563.75

June 21, 2011

Kentucky Utilities Company
Summary of Utility Plant
May 31, 2011

		Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101	**Utility Plant in Service**						
	Electric						
	Electric Distribution	$ 1,312,664,325.73	$ 21,551,703.21	$ (6,636,372.18)	$ 787,154.19	$ 15,702,485.22	$ 1,328,366,810.95
	Electric General Plant	125,243,994.19	7,480,512.57	(4,012,715.91)	(787,154.19)	2,680,642.47	127,924,636.66
	Electric Hydro Production	16,848,655.18	300,776.20	(15,190.72)	-	285,585.48	17,134,240.66
	Electric Intangible Plant	49,640,906.77	4,258,964.57	(1,381,084.50)	-	2,877,880.07	52,518,786.84
	Electric Other Production	519,412,128.33	1,149,283.17	(173,010.67)	-	976,272.50	520,388,400.83
	Electric Steam Production	1,814,421,935.78	20,129,237.62	(3,475,956.80)	120,828,152.53	137,481,433.35	1,951,903,369.13
	Electric Transmission	552,965,733.49	6,382,001.75	(1,164,824.32)	-	5,217,177.43	558,182,910.92
	Total 101 Accounts	4,391,197,679.47	61,252,479.09	(16,859,155.10)	120,828,152.53	165,221,476.52	4,556,419,155.99
102	**Electric Plant Purchased or Sold**						
	Electric						
	Electric Steam	483,341.17	-	-	-	-	483,341.17
	Total 102001	483,341.17	-	-	-	-	483,341.17
105	**Plant Held for Future Use**						
	Electric						
	Electric Distribution	792,599.21				-	792,599.21
	Electric Steam	120,828,152.53	-	-	(120,828,152.53)	(120,828,152.53)	-
	Total 105001	121,620,751.74	-	-	(120,828,152.53)	(120,828,152.53)	792,599.21
106	**Completed Construction Not Classified**						
	Electric						
	Electric Distribution	36,610,963.62	6,925,695.31	-	-	6,925,695.31	43,536,658.93
	Electric General Plant	769,342.30	3,409,814.03	-	-	3,409,814.03	4,179,156.33
	Electric Hydro Production	-	-	-	-	-	-
	Electric Intangible Plant	2,685,464.69	1,070,713.92	-	-	1,070,713.92	3,756,178.61
	Electric Other Production	3,737,695.33	1,027,623.11	-	-	1,027,623.11	4,765,318.44
	Electric Steam Production	910,748,505.16	675,648,991.88	-	-	675,648,991.88	1,586,397,497.04
	Electric Transmission	74,497,274.43	3,915,367.64	-	-	3,915,367.64	78,412,642.07
	Total 106 Accounts	1,029,049,245.53	691,998,205.89	-	-	691,998,205.89	1,721,047,451.42
121	**Nonutility Property**						
	Common						
	Non Utility Property	179,120.94	-	-	-	-	179,120.94
	Total 121001	179,120.94	-	-	-	-	179,120.94
107	**Construction Work In Progress**						
	Electric						
	Electric	954,430,277.48	(669,431,293.98)	-	-	(669,431,293.98)	284,998,983.50
	Total 107001	954,430,277.48	(669,431,293.98)	-	-	(669,431,293.98)	284,998,983.50
	Total Plant (Non-CWIP)	5,542,530,138.85	753,250,684.98	(16,859,155.10)	-	736,391,529.88	6,278,921,668.73
	Total Plant + CWIP	6,496,960,416.33	83,819,391.00	(16,859,155.10)	-	66,960,235.90	6,563,920,652.23
	Total Plant + CWIP - Nonutility (BS)	$ 6,496,781,295.39	$ 83,819,391.00	$ (16,859,155.10)	$ -	$ 66,960,235.90	$ 6,563,741,531.29

June 21, 2011

Kentucky Utilities Company
Summary of Utility Plant - Reserve for Depreciation of Utility Plant
May 31, 2011

	Beginning Balance	Accruals	Retirements	Transfers/ Adjustments	ARO Settlements	RWIP Transfers Out	Cost of Removal	Salvage	Other Credits	Ending Balance
Life Reserve										
Electric Distribution	$ (398,692,068.83)	$ (11,427,976.99)	$ 6,636,372.18	$ (181,198.53)	$ -	$ -	$ -	$ -	$ -	$ (403,664,872.17)
Electric Distribution - ARO	(790.87)	(1,847.25)	-	-	-	-	-	-	-	(2,638.12)
Electric General Plant	(57,721,732.75)	(2,432,684.84)	4,012,715.91	181,198.53	-	-	-	-	-	(55,960,503.15)
Electric Hydro Production	(7,765,077.65)	(49,567.42)	15,190.72	-	-	-	-	-	-	(7,799,454.35)
Electric Hydro Production - ARO	(121.57)	(405.40)	-	-	-	-	-	-	-	(526.97)
Electric Other Production	(160,412,820.60)	(6,965,434.67)	173,010.67	-	-	-	-	-	-	(167,205,244.60)
Electric Other Production - ARO	(84.76)	(282.85)	-	-	-	-	-	-	-	(367.61)
Electric Steam Production	(1,067,997,942.05)	(36,525,520.97)	3,450,660.64	-	-	-	-	-	-	(1,101,072,802.38)
Electric Steam Production - ARO	(485,952.30)	(1,241,791.89)	25,296.16	-	-	-	-	-	-	(1,702,448.03)
Electric Transmission	(211,361,531.11)	(3,836,081.69)	1,164,824.32	-	-	-	-	-	-	(214,032,788.48)
Electric Transmission - ARO	(156.99)	(523.50)	-	-	-	-	-	-	-	(680.49)
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	(1,904,438,279.48)	(62,482,117.47)	15,478,070.60	-	-	-	-	-	-	(1,951,442,326.35)
Cost of Removal										
Electric Distribution	(195,818,054.42)	(3,342,133.77)	-	0.02	-	-	983,197.55	-	-	(198,176,990.62)
Electric General Plant	207,510.70	(18,363.37)	-	(0.02)	-	-	23,483.98	-	-	212,631.29
Electric Hydro Production	(374,056.75)	(2,166.70)	-	-	-	-	29,260.00	-	-	(346,963.45)
Electric Other Production	(3,174,464.89)	(373,250.32)	-	-	-	-	1,251.94	-	-	(3,546,463.27)
Electric Steam Production	(113,988,699.33)	(10,260,175.14)	-	-	-	-	927,456.79	-	-	(123,321,417.68)
Electric Transmission	(137,175,896.62)	(1,157,359.43)	-	-	-	-	857,899.90	-	-	(137,475,356.15)
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	(450,323,661.31)	(15,153,448.73)	-	-	-	-	2,822,550.16	-	-	(462,654,559.88)
Salvage										
Electric Distribution	48,221,606.07	815,008.41	-	-	-	-	-	(94,214.96)	-	48,942,399.52
Electric General Plant	149,758.57	-	-	-	-	-	-	-	-	149,758.57
Electric Hydro Production	46,518.69	-	-	-	-	-	-	-	-	46,518.69
Electric Other Production	618,891.61	-	-	-	-	-	-	-	-	618,891.61
Electric Steam Production	20,938,580.66	1,957,848.61	-	-	-	-	-	(1,116,553.50)	-	21,779,875.77
Electric Transmission	23,009,336.80	268,764.60	-	-	-	-	-	(8,783.79)	-	23,269,317.61
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	92,984,692.40	3,041,621.62	-	-	-	-	-	(1,219,552.25)	-	94,806,761.77
Total Reserves										
Electric Distribution	(546,288,517.18)	(13,955,102.35)	6,636,372.18	(181,198.51)	-	-	983,197.55	(94,214.96)	-	(552,899,463.27)
Electric Distribution - ARO	(790.87)	(1,847.25)	-	-	-	-	-	-	-	(2,638.12)
Electric General Plant	(57,364,463.48)	(2,451,048.21)	4,012,715.91	181,198.51	-	-	23,483.98	-	-	(55,598,113.29)
Electric Hydro Production	(8,092,615.71)	(51,734.12)	15,190.72	-	-	-	29,260.00	-	-	(8,099,899.11)
Electric Hydro Production - ARO	(121.57)	(405.40)	-	-	-	-	-	-	-	(526.97)
Electric Other Production	(162,968,393.88)	(7,338,684.99)	173,010.67	-	-	-	1,251.94	-	-	(170,132,816.26)
Electric Other Production - ARO	(84.76)	(282.85)	-	-	-	-	-	-	-	(367.61)
Electric Steam Production	(1,161,048,060.72)	(44,827,847.50)	3,450,660.64	-	-	-	927,456.79	(1,116,553.50)	-	(1,202,614,344.29)
Electric Steam Production - ARO	(485,952.30)	(1,241,791.89)	25,296.16	-	-	-	-	-	-	(1,702,448.03)
Electric Transmission	(325,528,090.93)	(4,724,676.52)	1,164,824.32	-	-	-	857,899.90	(8,783.79)	-	(328,238,827.02)
Electric Transmission - ARO	(156.99)	(523.50)	-	-	-	-	-	-	-	(680.49)
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	(2,261,777,248.39)	(74,593,944.58)	15,478,070.60	-	-	-	2,822,550.16	(1,219,552.25)	-	(2,319,290,124.46)
Retirement Work in Process										
Electric	13,605,672.01	-	-	14,675.52	(42,353.83)	(1,560,644.08)	5,269,624.66	(463,269.49)	(175,499.84)	16,648,204.95
	13,605,672.01	-	-	14,675.52	(42,353.83)	(1,560,644.08)	5,269,624.66	(463,269.49)	(175,499.84)	16,648,204.95
YTD ACTIVITY	(2,248,171,576.38)	(74,593,944.58)	15,478,070.60	14,675.52	(42,353.83)	(1,560,644.08)	8,092,174.82	(1,682,821.74)	(175,499.84)	(2,302,641,919.51)
Amortization										
Electric	(13,755,205.98)	(2,896,481.06)	1,381,084.50	-	-	-	-	-	-	(15,270,602.54)
	(13,755,205.98)	(2,896,481.06)	1,381,084.50	-	-	-	-	-	-	(15,270,602.54)
Depreciation & Amortization Total										
Depreciation & Amortization Total	(2,261,926,782.36)	(77,490,425.64)	16,859,155.10	14,675.52	(42,353.83)	(1,560,644.08)	8,092,174.82	(1,682,821.74)	(175,499.84)	(2,317,912,522.05)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)	$ 4,234,854,513.03									$ 4,245,829,009.24

June 21, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of May 31, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues...................................	$ 125,468,971.21	$ -	$ 125,468,971.21
Rate Refunds...	-	-	-
Total Operating Revenues....................................	125,468,971.21	-	125,468,971.21
Fuel for Electric Generation.....................................	43,006,003.01	-	43,006,003.01
Power Purchased...	7,382,551.12	-	7,382,551.12
Other Operation Expenses.......................................	19,445,893.91	-	19,445,893.91
Maintenance..	12,995,142.09	-	12,995,142.09
Depreciation..	15,163,173.93	7.39	15,163,181.32
Amortization Expense...	596,216.66	-	596,216.66
Regulatory Credits...	(472,173.53)	-	(472,173.53)
Taxes			
Federal Income..	3,800,442.10	-	3,800,442.10
State Income..	2,296,685.49	-	2,296,685.49
Deferred Federal Income - Net..............................	2,955,121.48	(22,478.02)	2,932,643.46
Deferred State Income - Net..................................	(1,158,530.40)	(4,099.33)	(1,162,629.73)
Property and Other..	2,336,418.31	-	2,336,418.31
Loss (Gain) from Disposition of Allowances...........	-	-	-
Accretion Expense...	228,200.96	-	228,200.96
Total Operating Expenses.....................................	108,575,145.13	(26,569.96)	108,548,575.17
Net Operating Income...	16,893,826.08	26,569.96	16,920,396.04
Other Income Less Deductions			
Amortization of Investment Tax Credit.............	233,343.00	-	233,343.00
Other Income Less Deductions..........................	(149,931.87)	(73,840.35)	(223,772.22)
AFUDC - Equity...	2,838.02	-	2,838.02
Total Other Income Less Deductions....................	86,249.15	(73,840.35)	12,408.80
Income Before Interest Charges............................	16,980,075.23	(47,270.39)	16,932,804.84
Interest on Long-Term Debt....................................	5,115,872.14	(5,525.49)	5,110,346.65
Amortization of Debt Expense - Net........................	317,143.66	-	317,143.66
Other Interest Expenses...	363,856.49	-	363,856.49
AFUDC - Borrowed Funds......................................	(863.05)	-	(863.05)
Total Interest Charges...	5,796,009.24	(5,525.49)	5,790,483.75
Net Income..	$ 11,184,065.99	$ (41,744.90)	$ 11,142,321.09

Note: Purchase accounting is subject to change through October 31, 2011

June 21, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of May 31, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 638,207,116.60	$ -	$ 638,207,116.60
Rate Refunds	-	-	-
Total Operating Revenues	638,207,116.60	-	638,207,116.60
Fuel for Electric Generation	206,338,949.86	-	206,338,949.86
Power Purchased	52,732,613.66	-	52,732,613.66
Other Operation Expenses	94,567,796.19	31,612.30	94,599,408.49
Maintenance	53,378,600.49	-	53,378,600.49
Depreciation	74,510,678.39	0.05	74,510,678.44
Amortization Expense	2,896,481.06	-	2,896,481.06
Regulatory Credits	(2,377,269.39)	-	(2,377,269.39)
Taxes			
Federal Income	12,914,832.81	-	12,914,832.81
State Income	5,473,123.61	-	5,473,123.61
Deferred Federal Income - Net	25,086,797.31	(49,897.97)	25,036,899.34
Deferred State Income - Net	618,278.43	(9,099.93)	609,178.50
Property and Other	11,576,658.12	-	11,576,658.12
Loss (Gain) from Disposition of Allowances	(3,293.39)	-	(3,293.39)
Accretion Expense	1,132,418.50	-	1,132,418.50
Total Operating Expenses	538,846,665.65	(27,385.55)	538,819,280.10
Net Operating Income	99,360,450.95	27,385.55	99,387,836.50
Other Income Less Deductions			
Amortization of Investment Tax Credit	1,053,004.00	-	1,053,004.00
Other Income Less Deductions	84,336.92	984,449.81	1,068,786.73
AFUDC - Equity	10,357.55	-	10,357.55
Total Other Income Less Deductions	1,147,698.47	984,449.81	2,132,148.28
Income Before Interest Charges	100,508,149.42	1,011,835.36	101,519,984.78
Interest on Long-Term Debt	25,651,613.92	(27,627.46)	25,623,986.46
Amortization of Debt Expense - Net	1,482,833.95	-	1,482,833.95
Other Interest Expenses	2,304,294.40	-	2,304,294.40
AFUDC - Borrowed Funds	(3,144.82)	-	(3,144.82)
Total Interest Charges	29,435,597.45	(27,627.46)	29,407,969.99
Net Income	$ 71,072,551.97	$ 1,039,462.82	$ 72,112,014.79

Note: Purchase accounting is subject to change through October 31, 2011

June 21, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of May 31, 2011

Retained Earnings and Undistributed Earnings	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,467,482,992.80	$ 15,189,482.75	$ (1,402,623,482.66)	$ (14,683,861.84)	$ 64,859,510.14	$ 505,620.91
Add						
Net Income for Period..	11,184,065.99	-	(41,744.90)	-	11,142,321.09	-
Deductions:						
Common Dividends						
Common Stock Without Par Value..................	(37,000,000.00)	-	-	-	(37,000,000.00)	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	(123,419.00)	123,419.00	73,840.35	(73,840.35)	(49,578.65)	49,578.65
Dividends Received Current Year						
EE Inc...	-	-	-	-	-	-
Balance at End of Period	$ 1,441,543,639.79	$ 15,312,901.75	$ (1,402,591,387.21)	$ (14,757,702.19)	$ 38,952,252.58	$ 555,199.56
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings...............		15,312,901.75		(14,757,702.19)		555,199.56
Statutory Tax Rate..		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.........................		$ 5,956,718.78		$ (5,740,746.15)		$ 215,972.63

Note: Purchase accounting is subject to change through October 31, 2011.

June 21, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of May 31, 2011

Retained Earnings and Undistributed Earnings	Year to Date without Purchase Accounting: Retained Earnings	Year to Date without Purchase Accounting: Undistributed Subsidiary Earnings	Year to Date Purchase Accounting: Retained Earnings	Year to Date Purchase Accounting: Undistributed Subsidiary Earnings	Year to Date Combined: Retained Earnings	Year to Date Combined: Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,439,351,593.82	$ 14,432,395.75	$ (1,404,000,051.78)	$ (14,388,500.44)	$ 35,351,542.04	$ 43,895.31
Add						
Net Income for Period ……………………………	71,072,551.97	-	1,039,462.82	-	72,112,014.79	-
Deductions:						
Common Dividends						
Common Stock Without Par Value....................	(68,000,000.00)	-	-	-	(68,000,000.00)	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc………………………..…………	(880,506.00)	880,506.00	369,201.75	(369,201.75)	(511,304.25)	511,304.25
Dividends Received Current Year						
EE Inc………………………………………	-		-	-	-	-
Balance at End of Period …...……………………………	$ 1,441,543,639.79	$ 15,312,901.75	$ (1,402,591,387.21)	$ (14,757,702.19)	$ 38,952,252.58	$ 555,199.56
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings…………		15,312,901.75		(14,757,702.19)		555,199.56
Statutory Tax Rate…...…………………………………		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary…...…………….		$ 5,956,718.78		$ (5,740,746.15)		$ 215,972.63

Note: Purchase accounting is subject to change through October 31, 2011

June 21, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of May 31, 2011

Retained Earnings and Undistributed Earnings	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,377,532,218.85	$ 12,612,486.75	$ -	$ -	$ 1,377,532,218.85	$ 12,612,486.75
Add						
Net Income for Period...	184,711,835.94	-	975,297.20	-	185,687,133.14	-
Purchase Accounting Deductions:	-	-	(1,404,083,566.85)	(14,240,819.75)	(1,404,083,566.85)	(14,240,819.75)
Deductions:						
Common Dividends						
Common Stock Without Par Value..................	(118,000,000.00)	-	-	-	(118,000,000.00)	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	(2,700,415.00)	2,700,415.00	516,882.44	(516,882.44)	(2,183,532.56)	2,183,532.56
Dividends Received Current Year						
EE Inc...	-	-	-	-	-	-
Balance at End of Period	$ 1,441,543,639.79	$ 15,312,901.75	$ (1,402,591,387.21)	$ (14,757,702.19)	$ 38,952,252.58	$ 555,199.56

Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings................		15,312,901.75		(14,757,702.19)		555,199.56
Statutory Tax Rate..		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.........................		$ 5,956,718.78		$ (5,740,746.15)		$ 215,972.63

Combined Balance of Retained Earnings	12 MONTHS 05/31/11	12 MONTHS 5/31/2010
Retained Earnings at Beginning of Period.......................	$ 1,390,144,705.60	$ 1,220,094,633.64
Net Income for Period	185,687,133.14	170,050,071.96
FIN 48 Adjustment..	-	-
Subtotal...	1,575,831,838.74	1,390,144,705.60
Deduct		
Purchase Accounting Adjustment.............................	1,418,324,386.60	
Dividends on Common Stock....................................	118,000,000.00	-
Retained Earnings at End of Period................................	$ 39,507,452.14	$ 1,390,144,705.60

Note: Purchase accounting is subject to change through October 31, 2011

June 21, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of May 31, 2011

Assets	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Utility Plant			
Utility Plant at Original Cost......................................	$ 6,563,741,531.29	$ (0.05)	$ 6,563,741,531.24
Less Reserves for Depreciation and Amortization......	2,317,912,522.05	-	2,317,912,522.05
Total..	4,245,829,009.24	(0.05)	4,245,829,009.19
Investments			
Electric Energy, Inc..	12,528,864.55	17,204,800.56	29,733,665.11
Ohio Valley Electric Corporation...............................	250,000.00	-	250,000.00
Nonutility Property - Less Reserve............................	179,120.94	-	179,120.94
Special Funds...	-	-	-
Total..	12,957,985.49	17,204,800.56	30,162,786.05
Current and Accrued Assets			
Cash..	36,897,070.19	-	36,897,070.19
Special Deposits...	823,713.19	-	823,713.19
Temporary Cash Investments...................................	10,792.75	-	10,792.75
Accounts Receivable-Less Reserve...........................	152,810,722.21	-	152,810,722.21
Notes Receivable from Assoc Companies................	-	-	-
Accounts Receivable from Assoc Companies...........	-	-	-
Materials & Supplies-At Average Cost			
Fuel...	96,484,082.93	-	96,484,082.93
Plant Materials & Operating Supplies.....................	33,123,080.35	-	33,123,080.35
Stores Expense..	9,417,290.34	-	9,417,290.34
Allowance Inventory...	523,516.78	-	523,516.78
Prepayments..	7,342,581.45	-	7,342,581.45
Miscellaneous Current & Accrued Assets.................	103,768.46	-	103,768.46
Total..	337,536,618.65	-	337,536,618.65
Deferred Debits and Other			
Unamortized Debt Expense..	21,884,073.12	(4,536,144.22)	17,347,928.90
Unamortized Loss on Bonds......................................	12,128,018.10	-	12,128,018.10
Accumulated Deferred Income Taxes........................	88,931,970.66	75,035,179.20	163,967,149.86
Deferred Regulatory Assets..	280,194,551.01	18,313,787.38	298,508,338.39
Other Deferred Debits..	43,422,416.86	167,958,338.13	211,380,754.99
Goodwill...	-	607,404,368.23	607,404,368.23
Total..	446,561,029.75	864,175,528.72	1,310,736,558.47
Total Assets..	$ 5,042,884,643.13	$ 881,380,329.23	$ 5,924,264,972.36

Note: Purchase accounting is subject to change through October 31, 2011

June 21, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of May 31, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Proprietary Capital			
Common Stock...	$ 308,139,977.56	$ -	$ 308,139,977.56
Less: Common Stock Expense....................................	321,288.87	-	321,288.87
Paid-In Capital..	315,858,083.00	2,032,588,750.94	2,348,446,833.94
Other Comprehensive Income....................................	(2,488,203.95)	1,990,823.26	(497,380.69)
Retained Earnings...	1,441,543,639.79	(1,402,591,387.21)	38,952,252.58
Unappropriated Undistributed Subsidiary Earnings....	15,312,901.75	(14,757,702.19)	555,199.56
Total Proprietary Capital..	2,078,045,109.28	617,230,484.80	2,695,275,594.08
Pollution Control Bonds - Net of Reacquired Bonds...	350,779,405.00	1,122,776.56	351,902,181.56
First Mortgage Bonds..	1,489,441,593.75	-	1,489,441,593.75
Total Long-Term Debt..	1,840,220,998.75	1,122,776.56	1,841,343,775.31
Total Capitalization..	3,918,266,108.03	618,353,261.36	4,536,619,369.39
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies..............	-	-	-
Notes Payable..	-	-	-
Accounts Payable..	77,334,267.91	-	77,334,267.91
Accounts Payable to Associated Companies..............	31,038,474.94	-	31,038,474.94
Customer Deposits..	23,248,184.46	-	23,248,184.46
Taxes Accrued..	21,639,563.75	-	21,639,563.75
Interest Accrued..	6,773,699.99	-	6,773,699.99
Dividends Declared...	37,000,000.00	-	37,000,000.00
Miscellaneous Current and Accrued Liabilities..........	17,504,558.93	-	17,504,558.93
Total..	214,538,749.98	-	214,538,749.98
Deferred Credits and Other			
Accumulated Deferred Income Taxes........................	477,326,620.69	81,291,086.58	558,617,707.27
Investment Tax Credit..	103,041,165.32	-	103,041,165.32
Regulatory Liabilities..	114,137,068.78	167,958,338.13	282,095,406.91
Customer Advances for Construction.........................	2,772,266.47	-	2,772,266.47
Asset Retirement Obligations.....................................	55,055,329.65	-	55,055,329.65
Other Deferred Credits..	19,921,934.09	13,777,643.16	33,699,577.25
Miscellaneous Long-Term Liabilities.........................	2,388,318.25	-	2,388,318.25
Accum Provision for Postretirement Benefits............	135,437,081.87	-	135,437,081.87
Total..	910,079,785.12	263,027,067.87	1,173,106,852.99
Total Liabilities and Stockholders' Equity.......................	$ 5,042,884,643.13	$ 881,380,329.23	$ 5,924,264,972.36

Note: Purchase accounting is subject to change through October 31, 2011

June 21, 2011

KENTUCKY UTILITIES COMPANY

Financial Reports

April 30, 2011

Index
Financial and Operating Reports

Kentucky Utilities Company
April 30, 2011

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2011 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows, unless otherwise noted.

Kentucky Utilities Company
Comparative Statement of Income
April 30, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 107,312,923.69	$ 103,746,048.86	$ 3,566,874.83	3.44
Rate Refunds	-	-	-	-
Total Operating Revenues	107,312,923.69	103,746,048.86	3,566,874.83	3.44
Fuel for Electric Generation	32,088,589.82	27,726,784.09	4,361,805.73	15.73
Power Purchased	11,778,662.25	14,988,604.35	(3,209,942.10)	(21.42)
Other Operation Expenses	17,821,259.16	17,025,606.16	795,653.00	4.67
Maintenance	15,523,681.30	9,089,599.96	6,434,081.34	70.79
Depreciation	15,165,884.45	10,809,368.57	4,356,515.88	40.30
Amortization Expense	587,302.91	525,416.58	61,886.33	11.78
Regulatory Credits	(495,970.94)	(208,010.82)	(287,960.12)	(138.44)
Taxes				
Federal Income	2,025,840.91	4,989,297.46	(2,963,456.55)	(59.40)
State Income	369,454.26	909,902.28	(540,448.02)	(59.40)
Deferred Federal Income - Net	-	125,072.31	(125,072.31)	(100.00)
Deferred State Income - Net	-	22,809.54	(22,809.54)	(100.00)
Property and Other	2,501,068.96	1,464,618.61	1,036,450.35	70.77
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	-	-	-	-
Accretion Expense	227,486.03	183,265.83	44,220.20	24.13
Total Operating Expenses	97,593,259.11	87,652,334.92	9,940,924.19	11.34
Net Operating Income	9,719,664.58	16,093,713.94	(6,374,049.36)	(39.61)
Other Income Less Deductions				
Amortization of Investment Tax Credit	233,343.00	5,925.00	227,418.00	3,838.28
Other Income Less Deductions	(523,257.23)	(609,391.59)	86,134.36	14.13
AFUDC - Equity	2,587.63	(11,601.23)	14,188.86	122.30
Total Other Income Less Deductions	(287,326.60)	(615,067.82)	327,741.22	53.29
Income Before Interest Charges	9,432,337.98	15,478,646.12	(6,046,308.14)	(39.06)
Interest on Long-Term Debt	5,157,059.19	6,333,688.35	(1,176,629.16)	(18.58)
Amortization of Debt Expense - Net	293,849.87	68,395.59	225,454.28	329.63
Other Interest Expenses	507,098.74	274,485.97	232,612.77	84.74
AFUDC - Borrowed Funds	(786.20)	(81,138.25)	80,352.05	99.03
Total Interest Charges	5,957,221.60	6,595,431.66	(638,210.06)	(9.68)
Net Income	$ 3,475,116.38	$ 8,883,214.46	$ (5,408,098.08)	(60.88)

May 26, 2011

Kentucky Utilities Company
Comparative Statement of Income
April 30, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 512,738,145.39	$ 484,271,380.80	$ 28,466,764.59	5.88
Rate Refunds	-	(987,769.21)	987,769.21	100.00
Total Operating Revenues	512,738,145.39	483,283,611.59	29,454,533.80	6.09
Fuel for Electric Generation	163,332,946.85	153,910,834.48	9,422,112.37	6.12
Power Purchased	45,350,062.54	68,990,949.38	(23,640,886.84)	(34.27)
Other Operation Expenses	75,121,902.28	67,479,076.42	7,642,825.86	11.33
Maintenance	40,383,458.40	32,016,469.15	8,366,989.25	26.13
Depreciation	59,347,504.46	43,134,728.55	16,212,775.91	37.59
Amortization Expense	2,300,264.40	2,247,432.51	52,831.89	2.35
Regulatory Credits	(1,905,095.86)	(826,491.91)	(1,078,603.95)	(130.50)
Taxes				
Federal Income	9,114,390.71	19,799,017.34	(10,684,626.63)	(53.97)
State Income	3,176,438.12	3,442,092.39	(265,654.27)	(7.72)
Deferred Federal Income - Net	22,131,675.83	6,735,680.77	15,395,995.06	228.57
Deferred State Income - Net	1,776,808.83	1,330,268.67	446,540.16	33.57
Property and Other	9,240,239.81	6,759,417.97	2,480,821.84	36.70
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	(3,293.39)	(44,023.81)	40,730.42	92.52
Accretion Expense	904,217.54	727,398.35	176,819.19	24.31
Total Operating Expenses	430,271,520.52	405,702,850.26	24,568,670.26	6.06
Net Operating Income	82,466,624.87	77,580,761.33	4,885,863.54	6.30
Other Income Less Deductions				
Amortization of Investment Tax Credit	819,661.00	23,700.00	795,961.00	3,358.49
Other Income Less Deductions	234,268.79	1,677,937.65	(1,443,668.86)	(86.04)
AFUDC - Equity	7,519.53	(47,973.00)	55,492.53	115.67
Total Other Income Less Deductions	1,061,449.32	1,653,664.65	(592,215.33)	(35.81)
Income Before Interest Charges	83,528,074.19	79,234,425.98	4,293,648.21	5.42
Interest on Long-Term Debt	20,535,741.78	25,479,747.52	(4,944,005.74)	(19.40)
Amortization of Debt Expense - Net	1,165,690.29	273,581.97	892,108.32	326.08
Other Interest Expenses	1,940,437.91	1,170,956.07	769,481.84	65.71
AFUDC - Borrowed Funds	(2,281.77)	(319,448.33)	317,166.56	99.29
Total Interest Charges	23,639,588.21	26,604,837.23	(2,965,249.02)	(11.15)
Net Income	$ 59,888,485.98	$ 52,629,588.75	$ 7,258,897.23	13.79

May 26, 2011

Kentucky Utilities Company
Comparative Statement of Income
April 30, 2011

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues.....................................	$ 1,540,808,860.51	$ 1,373,376,681.82	$ 167,432,178.69	12.19
Rate Refunds..	355,385.29	(1,457,000.00)	1,812,385.29	124.39
Total Operating Revenues......................................	1,541,164,245.80	1,371,919,681.82	169,244,563.98	12.34
Fuel for Electric Generation......................................	505,506,300.50	444,689,645.48	60,816,655.02	13.68
Power Purchased...	150,981,050.43	187,230,115.93	(36,249,065.50)	(19.36)
Other Operation Expenses..	224,290,053.63	196,891,228.70	27,398,824.93	13.92
Maintenance..	116,180,974.05	48,866,076.68	67,314,897.37	137.75
Depreciation..	155,494,816.60	128,377,347.69	27,117,468.91	21.12
Amortization Expense...	6,656,295.81	6,745,245.92	(88,950.11)	(1.32)
Regulatory Credits..	(6,228,161.30)	(2,444,614.47)	(3,783,546.83)	(154.77)
Taxes				
Federal Income...	50,974,822.65	18,285,371.83	32,689,450.82	178.77
State Income...	12,490,738.24	4,486,927.95	8,003,810.29	178.38
Deferred Federal Income - Net...............................	37,671,446.81	48,228,528.07	(10,557,081.26)	(21.89)
Deferred State Income - Net...................................	3,757,578.34	9,179,838.46	(5,422,260.12)	(59.07)
Property and Other...	22,374,300.81	19,995,475.53	2,378,825.28	11.90
Investment Tax Credit..	-	16,062,341.26	(16,062,341.26)	(100.00)
Loss (Gain) from Disposition of Allowances...........	(16,020.32)	(44,023.81)	28,003.49	63.61
Accretion Expense..	3,675,724.13	2,144,767.27	1,530,956.86	71.38
Total Operating Expenses......................................	1,283,809,920.38	1,128,694,272.49	155,115,647.89	13.74
Net Operating Income...	257,354,325.42	243,225,409.33	14,128,916.09	5.81
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	867,061.00	115,161.25	751,899.75	652.91
Other Income Less Deductions...........................	(385,754.94)	1,935,300.56	(2,321,055.50)	(119.93)
AFUDC - Equity...	576,644.57	1,635,852.72	(1,059,208.15)	(64.75)
Total Other Income Less Deductions.....................	1,057,950.63	3,686,314.53	(2,628,363.90)	(71.30)
Income Before Interest Charges.............................	258,412,276.05	246,911,723.86	11,500,552.19	4.66
Interest on Long-Term Debt......................................	69,500,436.48	74,445,859.25	(4,945,422.77)	(6.64)
Amortization of Debt Expense - Net.........................	2,081,050.23	820,372.10	1,260,678.13	153.67
Other Interest Expenses..	4,728,904.81	3,406,104.54	1,322,800.27	38.84
AFUDC - Borrowed Funds.......................................	(651,430.37)	(1,031,812.30)	380,381.93	36.87
Total Interest Charges..	75,658,961.15	77,640,523.59	(1,981,562.44)	(2.55)
Net Income..	$ 182,753,314.90	$ 169,271,200.27	$ 13,482,114.63	7.96

May 26, 2011

Kentucky Utilities Company
Analysis of Retained Earnings
April 30, 2011

Retained Earnings and Undistributed Earnings	Current Month: Total Retained Earnings	Current Month: Undistributed Subsidiary Earnings	Year to Date: Total Retained Earnings	Year to Date: Undistributed Subsidiary Earnings	Year Ended Current Month: Total Retained Earnings	Year Ended Current Month: Undistributed Subsidiary Earnings
Balance at Beginning of Period..	$ 1,463,485,376.42	$ 15,711,982.75	$ 1,439,351,593.82	$ 14,432,395.75	$ 1,367,700,691.90	$ 13,218,468.75
Add:						
Net Income for Period..	3,475,116.38	-	59,888,485.98	-	182,753,314.90	-
Deduct:						
Common Dividends						
Common Stock Without Par Value	-	-	(31,000,000.00)	-	(81,000,000.00)	-
EE Inc..	522,500.00	(522,500.00)	(757,087.00)	757,087.00	(1,971,014.00)	1,971,014.00
Balance at End of Period...	1,467,482,992.80	15,189,482.75	1,467,482,992.80	15,189,482.75	1,467,482,992.80	15,189,482.75

Deferred Taxes Related to Undistributed Subsidiary Earnings	Current Month	Year to Date	Year Ended Current Month
Balance of Undistributed Subsidiary Earnings.............................	15,189,482.75	15,189,482.75	15,189,482.75
Statutory Tax Rate...	38.9%	38.9%	38.9%
Deferred Taxes on Equity in Subsidiary.......................................	5,908,708.79	5,908,708.79	5,908,708.79

Combined Balance of Retained Earnings	12 MONTHS 4/30/2011	12 MONTHS 4/30/2010
Retained Earnings at Beginning of Period....................................	1,380,919,160.65	1,211,647,960.38
Net Income..	182,753,314.90	169,271,200.27
Subtotal..	1,563,672,475.55	1,380,919,160.65
Deduct		
Dividends on Common Stock...	81,000,000.00	-
Retained Earnings at End of Period..	$ 1,482,672,475.55	$ 1,380,919,160.65

May 26, 2011

Kentucky Utilities Company
Comparative Balance Sheets as of April 30, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost......................................	$ 6,550,066,017.30	$ 6,232,839,506.60
Less Reserves for Depreciation and Amortization......	2,306,395,263.89	2,202,907,547.67
Total...	4,243,670,753.41	4,029,931,958.93
Investments		
Electric Energy, Inc...	12,399,562.55	14,514,268.75
Ohio Valley Electric Company..................................	250,000.00	250,000.00
Nonutility Property-Less Reserve..............................	179,120.94	179,120.94
Total...	12,828,683.49	14,943,389.69
Current and Accrued Assets		
Cash...	31,010,711.31	1,655,521.02
Special Deposits...	747,761.07	-
Temporary Cash Investments.....................................	25,009,882.51	269.25
Accounts Receivable-Less Reserve...........................	146,865,268.36	150,304,914.74
Accounts Receivable from Associated Companies.....	-	2,147.77
Materials and Supplies-At Average Cost		
Fuel...	96,058,692.86	114,591,215.10
Plant Materials and Operating Supplies..................	33,092,118.40	31,385,407.88
Stores Expense..	9,379,577.69	8,008,990.61
Emission Allowances...	530,898.99	778,104.25
Prepayments...	7,953,538.67	5,899,068.78
Miscellaneous Current and Accrued Assets................	119,965.13	531,218.02
Total...	350,768,414.99	313,156,857.42
Deferred Debits and Other		
Unamortized Debt Expense.......................................	21,001,779.68	4,770,828.36
Unamortized Loss on Bonds......................................	12,178,432.49	12,782,964.79
Accumulated Deferred Income Taxes........................	95,312,656.15	46,235,144.29
Deferred Regulatory Assets.......................................	278,119,589.05	231,967,759.79
Other Deferred Debits..	44,182,569.04	42,461,277.08
Total...	450,795,026.41	338,217,974.31
Total Assets	$ 5,058,062,878.30	$ 4,696,250,180.35

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense...................................	321,288.87	321,288.87
Paid-In Capital...	315,858,083.00	315,858,083.00
Other Comprehensive Income...................................	(2,494,086.95)	-
Retained Earnings..	1,467,482,992.80	1,367,700,691.90
Unappropriated Undistributed Subsidiary Earnings...	15,189,482.75	13,218,468.75
Total Proprietary Capital..	2,103,855,160.29	2,004,595,932.34
Pollution Control Bonds..	350,779,405.00	350,779,405.00
First Mortgage Bonds..	1,489,388,656.25	-
LT Notes Payable to Associated Companies..............	-	1,298,000,000.00
Total Long-Term Debt...	1,840,168,061.25	1,648,779,405.00
Total Capitalization..	3,944,023,221.54	3,653,375,337.34
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies..............	-	89,583,954.00
Accounts Payable..	71,282,791.92	90,580,991.56
Accounts Payable to Associated Companies.............	41,019,000.60	50,765,337.71
Customer Deposits...	22,926,426.59	22,714,611.64
Taxes Accrued..	13,958,987.99	16,321,649.81
Interest Accrued...	28,616,817.96	1,152,007.45
Miscellaneous Current and Accrued Liabilities..........	21,209,081.21	20,515,487.72
Total...	199,013,106.27	291,634,039.89
Deferred Credits and Other		
Accumulated Deferred Income Taxes........................	482,369,779.76	387,794,312.81
Investment Tax Credit..	103,274,508.32	104,141,569.32
Regulatory Liabilities...	115,217,224.39	47,725,572.31
Customer Advances for Construction........................	2,870,420.89	3,086,646.42
Asset Retirement Obligations....................................	54,827,128.69	35,077,869.76
Other Deferred Credits...	17,527,358.73	19,967,703.54
Miscellaneous Long-Term Liabilities........................	2,384,017.09	2,628,519.48
Accum Provision for Postretirement Benefits............	136,556,112.62	150,818,609.48
Total...	915,026,550.49	751,240,803.12
Total Liabilities and Stockholders Equity.......................	$ 5,058,062,878.30	$ 4,696,250,180.35

May 26, 2011

Kentucky Utilities Company
Statement of Capitalization and Short-Term Debt
April 30, 2011

	Authorized Shares	Issued and Outstanding Shares	Issued and Outstanding Amount	Percent of Total Capital
Proprietary Capital				
Common Stock - Without Par...	80,000,000	37,817,878	$ 308,139,977.56	
Less: Common Stock Expense..			321,288.87	
Paid-In Capital..			315,858,083.00	
Other Comprehensive Income...			(2,494,086.95)	
Retained Earnings...			1,467,482,992.80	
Unappropriated Undistributed Subsidiary Earnings.............			15,189,482.75	
Total Proprietary Capital..			2,103,855,160.29	53.35
Long-Term Debt				
Pollution Control Bonds				
Mercer County 2000 Series A due 05/01/23 Var%...........			12,900,000.00	
Carroll County 2002 Series A due 02/01/32 Var%...........			20,930,000.00	
Carroll County 2002 Series B due 02/01/32 Var%...........			2,400,000.00	
Carroll County 2002 Series C due 10/01/32 Var%...........			96,000,000.00	
Mercer County 2002 Series A due 02/01/32 Var%...........			7,400,000.00	
Muhlenburg County 2002 Series A due 02/01/32 Var%...			2,400,000.00	
Carroll County 2004 Series A due 10/01/34 Var%...........			50,000,000.00	
Carroll County 2006 Series B due 10/01/34 Var%...........			54,000,000.00	
Carroll County 2007 Series A due 02/01/26 5.75%..........			17,875,000.00	
Trimble County 2007 Series A due 03/01/37 6.00%.........			8,927,000.00	
Carroll County 2008 Series A due 02/01/32 Var%...........			77,947,405.00	
Total Pollution Control Bonds..			350,779,405.00	8.89
First Mortgage Bonds				
First Mortgage Bond Due 11/01/15 1.625%.......................			250,000,000.00	
First Mortgage Bond Due 11/01/20 3.250%......................			500,000,000.00	
First Mortgage Bond Due 11/01/40 5.125%......................			750,000,000.00	
Total First Mortgage Bonds..			1,500,000,000.00	38.03
Less: First Mortgage Bonds Debt Discount				
First Mortgage Bond Due 11/01/15 1.625%.......................			(794,791.68)	
First Mortgage Bond Due 11/01/20 3.250%......................			(1,803,375.00)	
First Mortgage Bond Due 11/01/40 5.125%......................			(8,013,177.07)	
			(10,611,343.75)	(0.27)
Total First Mortgage Bonds - Net of Debt Discount............			1,489,388,656.25	37.76
Total Capitalization..			$ 3,944,023,221.54	100.00

May 26, 2011

Kentucky Utilities Company
Summary Trial Balance
April 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 6,550,066,017.30	$ 6,550,066,017.30
Reserves for Depreciation and Amortization		(2,306,395,263.89)
Depreciation of Plant	(2,290,558,844.48)	
Amortization of Plant	(15,836,419.41)	
Investments		12,828,683.49
Electric Energy, Inc	12,399,562.55	
Ohio Valley Electric Corporation	250,000.00	
Nonutility Property Reserve	179,120.94	
Cash	31,010,711.31	31,010,711.31
Special Deposits		747,761.07
MAN Margin Call	747,761.07	
Temporary Cash Investments	25,009,882.51	25,009,882.51
Accounts Receivable - Less Reserve		146,865,268.36
Customers - Active	72,739,476.37	
Unbilled Revenues	64,563,000.00	
Bechtel Liquidated Damages	9,944,175.60	
Insurance Claims	1,949,857.22	
IMPA	1,060,782.94	
IMEA	834,129.04	
Transmission Sales	779,858.69	
Damage Claims	435,050.71	
IMEA/IMPA Net Portion of Bechtel Liquidated damages	(993,262.50)	
Other	3,924,046.99	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	2,282,010.74	
Bechtel Reserve	(5,971,125.60)	
Reserve	(2,294,684.00)	
Accrual	(1,876,109.12)	
Recoveries	(405,901.62)	
A/R Miscellaneous	(106,037.10)	
Fuel		96,058,692.86
Coal 1,616,185.03 Tons @ $54.91 MMBtu 37,196,054.37 @ 238.59¢	88,745,902.88	
Fuel Oil 2,955,830.00 Gallons @ 245.27¢	7,249,644.20	
Gas Pipeline 12,020.70 Mcf @ $5.25	63,145.78	
Plant Materials and Operating Supplies		33,092,118.40
Regular Materials and Supplies	32,310,526.48	
Limestone 90,572.27 Tons @ $8.51	781,591.90	
Other Reagents	0.02	
Stores Expense Undistributed	9,379,577.69	9,379,577.69

May 26, 2011

Kentucky Utilities Company
Summary Trial Balance
April 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Emission Allowances	$ 530,898.99	$ 530,898.99
Prepayments		7,953,538.67
Insurance	5,559,291.51	
Lease	697,319.96	
Taxes	315,318.79	
Risk Management and Workers Compensation	75,000.00	
Other	1,306,608.41	
Miscellaneous Current Assets		119,965.13
Derivative Asset - Non-Hedging	116,671.74	
Miscellaneous Current Assets	3,293.39	
Unamortized Debt Expense		21,001,779.68
Carroll County 2002 Series A due 02/01/32 Var%	85,080.34	
Carroll County 2002 Series B due 02/01/32 Var%	59,133.62	
Mercer County 2002 Series A due 02/01/32 Var%	23,748.40	
Muhlenburg County 2002 Series A due 02/01/32 Var%	65,827.11	
Carroll County 2002 Series C due 10/01/32 Var%	1,577,508.70	
Carroll County 2006 Series B due 10/01/34 Var%	1,122,127.46	
Carroll County 2007 Series A due 02/01/26 5.75%	491,796.33	
Trimble County 2007 Series A due 03/01/37 6.00%	415,185.02	
Carroll County 2008 Series A due 02/01/32 Var%	713,793.21	
First Mortgage Bond due 11/01/15 1.625%	1,892,754.54	
First Mortgage Bond due 11/01/20 3.250%	3,739,309.40	
First Mortgage Bond due 11/01/40 5.125%	7,069,680.72	
Revolving Credit Agreement	3,745,834.83	
Unamortized Loss on Bonds		12,178,432.49
Refinanced and Called Bonds	12,178,432.49	
Accumulated Deferred Income Taxes		95,312,656.15
Federal	80,713,296.40	
State	14,599,359.75	
Regulatory Assets		278,119,589.05
Pension and Postretirement Benefits	117,274,368.11	
SFAS 109 - Deferred Taxes	77,695,312.78	
2009 Winter Storm	52,944,001.60	
Virginia Mountain Snowstorm	6,041,670.12	
VA Fuel Component Non-Current	5,165,000.00	
FERC Jurisdictional Pension Expense	5,176,491.65	
MISO Exit Fee	4,658,715.31	
Asset Retirement Obligations	3,397,549.30	
2008 Wind Storm	2,030,852.62	
Rate Case Expenses	1,894,725.38	
EKPC FERC Transmission Cost	948,308.34	
KCCS Funding	749,092.91	
CMRG Funding	128,049.97	
General Management Audit	15,450.96	
Other Deferred Debits	44,182,569.04	44,182,569.04
Total Assets	$ 5,058,062,878.30	$ 5,058,062,878.30

May 26, 2011

Kentucky Utilities Company
Summary Trial Balance
April 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 2,103,855,160.29
Common Stock	308,139,977.56	
Less: Common Stock Expense	321,288.87	
Paid-In Capital	315,858,083.00	
Other Comprehensive Income	(2,494,086.95)	
Retained Earnings	1,467,482,992.80	
Unappropriated Undistributed Subsidiary Earnings	15,189,482.75	
Bonds		1,840,168,061.25
Pollution Control Bonds - Net of Reacquired Bonds	350,779,405.00	
First Mortgage Bonds	1,489,388,656.25	
Accounts Payable		71,282,791.92
Regular	69,615,108.50	
Salaries and Wages Accrued	1,612,944.64	
Employee Withholdings Payable	54,738.78	
Accounts Payable to Associated Companies		41,019,000.60
LG&E - KU Energy Services/Louisville Gas and Electric Company	41,019,000.60	
Customers' Deposits	22,926,426.59	22,926,426.59
Taxes Accrued	13,958,987.99	13,958,987.99
Interest Accrued		28,616,817.96
Mercer County 2000 Series A due 05/01/23 Var%	2,763.78	
Carroll County 2002 Series A due 02/01/32 Var%	33,964.77	
Carroll County 2002 Series B due 02/01/32 Var%	263.01	
Mercer County 2002 Series A due 02/01/32 Var%	4,004.11	
Muhlenburg County 2002 Series A due 02/01/32 Var%	263.01	
Carroll County 2002 Series C due 10/01/32 Var%	14,496.00	
Carroll County 2004 Series A due 10/01/34 Var%	10,794.52	
Carroll County 2006 Series B due 10/01/34 Var%	11,598.90	
Carroll County 2007 Series A due 02/01/26 5.75%	428,255.21	
Trimble County 2007 Series A due 03/01/37 6.00%	223,175.00	
Carroll County 2008 Series A due 02/01/32 Var%	16,721.32	
First Mortgage Bond due 11/01/15 1.625%	1,861,979.17	
First Mortgage Bond due 11/01/20 3.250%	7,447,916.67	
First Mortgage Bond due 11/01/40 5.125%	17,617,187.50	
Customers' Deposits	920,960.97	
Other	22,474.02	

May 26, 2011

Kentucky Utilities Company
Summary Trial Balance
April 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Miscellaneous Current and Accrued Liabilities		$ 21,209,081.21
Franchise Fee Payable	7,048,952.26	
Vacation Pay Accrued	6,672,878.07	
Tax Collections Payable	3,676,714.61	
Customer Overpayments	3,101,431.67	
Derivative Liabilities - Non-Hedging	533,238.77	
Home Energy Assistance	126,757.19	
Escheated Deposits	(200.91)	
Other	49,309.55	
Accumulated Deferred Income Taxes		482,369,779.76
Federal	416,888,538.39	
State	65,481,241.37	
Investment Tax Credit		103,274,508.32
Advanced Coal Credit	100,454,037.00	
Job Development Credit	2,820,471.32	
Regulatory Liabilities		115,217,224.39
Deferred Taxes		
Federal	63,146,624.40	
State	19,860,389.63	
Postretirement Benefits	9,787,090.00	
Environmental Cost Recovery	8,996,352.15	
DSM Cost Recovery	6,259,637.10	
Asset Retirement Obligations	4,460,784.08	
Spare Parts	1,825,456.64	
MISO Schedule 10 Charges	788,890.39	
Fuel Adjustment Clause	92,000.00	
Customers' Advances for Construction		2,870,420.89
Line Extensions	1,551,355.63	
Customer Advances	70,819.21	
Other	1,248,246.05	
Asset Retirement Obligations	54,827,128.69	54,827,128.69
Other Deferred Credits	17,527,358.73	17,527,358.73
Miscellaneous Long-Term Liabilities		2,384,017.09
Workers' Compensation	2,384,017.09	
Accumulated Provision for Benefits		136,556,112.62
Pension Payable	70,301,999.50	
Postretirement Benefits - SFAS 106	66,803,202.47	
Post Employment Benefits Payable	5,554,516.00	
Post Employment Medicare Subsidy	(382,793.62)	
Medicare Subsidy - SFAS 106	(5,720,811.73)	
Total Liabilities and Stockholders Equity	$ 5,058,062,878.30	$ 5,058,062,878.30

May 26, 2011

Kentucky Utilities Company
Statement of Cash Flows
April 30, 2011

	Year to Date	
	2011	2010
Cash Flows from Operating Activities		
Net income	$ 59,888,485.98	$ 52,629,588.75
Items not requiring (providing) cash currently:		
Depreciation	59,347,504.46	43,134,728.55
Amortization	2,300,264.40	2,247,432.51
Deferred income taxes - net	24,984,705.04	8,065,949.44
Investment Tax Credit	(843,359.00)	-
Gain on disposal of assets	24,755.92	-
Other	(10,903,983.21)	7,488,672.72
Change in receivables	57,941,546.62	31,841,145.58
Change in inventory	(2,216,718.11)	(18,290,900.37)
Change in allowance inventory	35,680.01	196,971.65
Change in payables and accrued expenses	3,575,990.09	(16,474,150.20)
Change in regulatory assets	(61,745,162.64)	21,703,989.26
Change in regulatory liabilities	60,104,593.99	3,481,128.91
Change in other deferred debits	(8,265,355.39)	(2,080,793.15)
Change in other deferred credits	9,242,933.57	10,090,540.59
Other	(38,938,868.10)	(20,480,347.54)
Less: Allowance for other funds used during construction	(5,237.76)	(271,475.33)
Less: Undistributed earnings of subsidiary company	(757,087.00)	(2,547,100.00)
Net cash provided (used) by operating activities	153,770,688.87	120,735,381.37
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(55,274,920.61)	(132,521,194.74)
Less: Allowance for other funds used during construction	5,237.76	271,475.33
Proceeds received from sales of property	(11,540.76)	-
Change in derivatives	(2,786.34)	(111,124.62)
Change in restricted cash	(138,584.56)	-
Other	(3,686,527.71)	-
Net cash provided (used) by investing activities	(59,109,122.22)	(132,360,844.03)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(540,419.69)	(104.40)
Net change in short-term debt	(10,434,000.00)	11,609,000.00
Dividends on common stock	(31,000,000.00)	-
Net cash provided (used) by financing activities	(41,974,419.69)	11,608,895.60
Net Increase (Decrease) in Cash and Cash Equivalents	52,687,146.96	(16,567.06)
Cash and Cash Equivalents at Beginning of Period	3,333,446.86	1,672,357.33
Cash and Cash Equivalents at End of Period	$ 56,020,593.82	$ 1,655,790.27

May 26, 2011

Kentucky Utilities Company
Analysis of Interest Charges
April 30, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Interest on Long-Term Debt						
Loan Agreement - Pollution Control Bonds						
Mercer County 2000 Series A due 05/01/23 Var%................	$ 2,763.37	$ 3,262.11	$ 11,153.67	$ 11,744.30	$ 41,618.80	$ 48,288.42
Carroll County 2002 Series A due 02/01/32 Var%................	41,028.53	11,124.45	84,287.70	55,937.59	176,781.11	211,507.68
Carroll County 2002 Series B due 02/01/32 Var%................	4,326.63	1,275.62	9,334.87	6,414.25	19,940.89	24,253.14
Mercer County 2002 Series A due 02/01/32 Var%................	13,309.87	3,933.15	27,603.02	19,777.27	60,304.94	74,780.55
Muhlenburg County 2002 Series A due 02/01/32 Var%........	4,316.74	1,275.62	8,952.36	6,414.25	19,558.38	24,253.14
Carroll County 2002 Series C due 10/01/32 Var%................	26,080.09	39,240.00	113,120.09	302,927.96	497,992.09	518,794.61
Carroll County 2004 Series A due 10/01/34 Var%................	10,794.41	13,000.00	48,410.85	43,287.67	155,424.55	155,041.10
Carroll County 2006 Series B due 10/01/34 Var%................	11,598.90	13,832.88	53,038.35	51,647.68	167,858.62	208,440.02
Carroll County 2007 Series A due 02/01/26 5.75%..............	85,651.05	85,651.04	342,604.17	342,604.17	1,027,812.50	1,027,812.50
Trimble County 2007 Series A due 03/01/37 6.00%.............	44,635.00	44,635.00	178,540.00	178,540.00	535,620.00	535,620.00
Carroll County 2008 Series A due 02/01/32 Var%................	16,721.30	19,945.99	75,363.38	74,402.39	241,188.47	299,036.15
Interest Rate Swaps..	-	-	-	-	-	-
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/01/15 1.625%...........................	338,541.65	-	1,354,166.66	-	1,861,979.17	-
First Mortgage Bond due 11/01/20 3.250%...........................	1,354,166.65	-	5,416,666.66	-	7,447,916.67	-
First Mortgage Bond due 11/01/40 5.125%...........................	3,203,125.00	-	12,812,500.00	-	17,617,187.50	-
Fidelia/PPL...	-	6,096,512.49	-	24,386,049.99	39,629,252.79	71,318,031.94
Total..	5,157,059.19	6,333,688.35	20,535,741.78	25,479,747.52	69,500,436.48	74,445,859.25
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense...................................	243,435.48	18,012.50	964,032.73	72,049.61	1,476,107.53	215,897.27
Amortization of Loss on Reacquired Debt.................................	50,414.39	50,383.09	201,657.56	201,532.36	604,942.70	604,474.83
Total..	293,849.87	68,395.59	1,165,690.29	273,581.97	2,081,050.23	820,372.10
Other Interest Charges						
Customers' Deposits..	106,452.28	116,741.54	425,582.88	499,012.74	1,290,140.01	1,237,343.86
Other Tax Deficiencies...	-	-	(84,914.00)	572.00	2,155.07	572.00
Interest on DSM Cost Recovery...	1,746.75	917.39	244.87	10,729.72	7,895.84	71,779.51
Interest on Debt to Associated Companies.................................	269.88	2,922.89	4,196.78	26,757.37	104,482.82	81,808.60
AFUDC Borrowed Funds..	(786.20)	(81,138.25)	(2,281.77)	(319,448.33)	(651,430.37)	(1,031,812.30)
Other Interest Expense..	398,629.83	153,904.15	1,595,327.38	633,884.24	3,324,231.07	2,014,600.57
Total..	506,312.54	193,347.72	1,938,156.14	851,507.74	4,077,474.44	2,374,292.24
Total Interest..	$ 5,957,221.60	$ 6,595,431.66	$ 23,639,588.21	$ 26,604,837.23	$ 75,658,961.15	$ 77,640,523.59

May 26, 2011

Kentucky Utilities Company
Analysis of Taxes Charged and Accrued
April 30, 2011

	Current Month		Year to Date	
Kind of Taxes	This Year	Last Year	This Year	Last Year
Taxes Charged to Accounts 408.1 and 409.1...........				
Property Taxes..	$ 1,494,264.00	$ 908,194.01	$ 5,977,056.00	$ 3,632,776.04
Unemployment..	3,297.33	4,225.68	74,020.12	76,078.05
FICA..	834,888.27	385,010.72	2,526,963.52	2,394,176.29
Public Service Commission Fee..............................	157,659.37	156,290.97	630,637.48	625,163.88
Federal Income..	2,025,840.91	4,989,297.46	9,114,390.71	19,799,017.34
State Income...	369,454.26	909,902.28	3,176,438.12	3,442,092.39
Miscellaneous..	10,959.99	10,897.23	31,562.69	31,223.71
Total Charged to Operating Expense..........	4,896,364.13	7,363,818.35	21,531,068.64	30,000,527.70
Taxes Charged to Other Accounts..........................	137,409.74	76,850.25	1,657,835.44	938,815.93
Taxes Accrued on Intercompany Accounts............	(265,109.89)	(248,724.53)	(1,506,337.55)	(1,071,750.95)
Total Taxes Charged..................................	$ 4,768,663.98	$ 7,191,944.07	$ 21,682,566.53	$ 29,867,592.68

Analysis of Taxes Accrued - Account 236

Kind of Taxes	Taxes Accrued At Beginning Of Year	Accruals To Date This Year	Payments To Date This Year	Taxes Accrued At End Of Month
Property Taxes..	$ 8,399,528.00	$ 5,977,724.00	$ 8,036,890.46	$ 6,340,361.54
Unemployment..	75,728.12	58,444.88	133,776.50	396.50
FICA..	639,011.24	2,020,564.74	2,430,899.52	228,676.46
Federal Income..	12,876,014.95	8,817,948.94	18,813,291.00	2,880,672.89
State Income...	2,021,178.48	3,573,258.79	1,477,172.00	4,117,265.27
Kentucky Sales and Use Tax..................................	581,659.33	1,132,237.86	1,333,715.93	380,181.26
Miscellaneous..	21,662.86	102,387.32	112,616.11	11,434.07
Totals..	$ 24,614,782.98	$ 21,682,566.53	$ 32,338,361.52	$ 13,958,987.99

May 26, 2011

Kentucky Utilities Company
Summary of Utility Plant
April 30, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant in Service**						
Electric						
Electric Distribution	$ 1,312,664,325.73	$ 17,881,273.32	$ (6,327,436.63)	$ 787,154.19	$ 12,340,990.88	$ 1,325,005,316.61
Electric General Plant	125,243,994.19	2,618,269.13	(4,012,536.85)	(787,154.19)	(2,181,421.91)	123,062,572.28
Electric Hydro Production	16,848,655.18	300,776.20	(15,190.72)	-	285,585.48	17,134,240.66
Electric Intangible Plant	49,640,906.77	3,000,330.38	(219,050.97)	-	2,781,279.41	52,422,186.18
Electric Other Production	519,412,128.33	447,823.94	(59,784.69)	-	388,039.25	519,800,167.58
Electric Steam Production	1,814,421,935.78	10,476,144.71	(2,599,047.54)	120,828,152.53	128,705,249.70	1,943,127,185.48
Electric Transmission	552,965,733.49	4,058,652.02	(407,344.55)	-	3,651,307.47	556,617,040.96
Total 101 Accounts	4,391,197,679.47	38,783,269.70	(13,640,391.95)	120,828,152.53	145,971,030.28	4,537,168,709.75
102 **Electric Plant Purchased or Sold**						
Electric						
Electric Steam	483,341.17	-	-	-	-	483,341.17
Total 102001	483,341.17	-	-	-	-	483,341.17
105 **Plant Held for Future Use**						
Electric						
Electric Distribution	792,599.21	-	-	-	-	792,599.21
Electric Steam	120,828,152.53	-	-	(120,828,152.53)	(120,828,152.53)	-
Total 105001	121,620,751.74	-	-	(120,828,152.53)	(120,828,152.53)	792,599.21
106 **Completed Construction Not Classified**						
Electric						
Electric Distribution	36,610,963.62	6,354,775.62	-	-	6,354,775.62	42,965,739.24
Electric General Plant	769,342.30	3,603,777.04	-	-	3,603,777.04	4,373,119.34
Electric Hydro Production	-	-	-	-	-	-
Electric Intangible Plant	2,685,464.69	168,185.51	-	-	168,185.51	2,853,650.20
Electric Other Production	3,737,695.33	2,249,051.97	-	-	2,249,051.97	5,986,747.30
Electric Steam Production	910,748,505.16	683,362,158.12	-	-	683,362,158.12	1,594,110,663.28
Electric Transmission	74,497,274.43	4,238,393.12	-	-	4,238,393.12	78,735,667.55
Total 106 Accounts	1,029,049,245.53	699,976,341.38	-	-	699,976,341.38	1,729,025,586.91
121 **Nonutility Property**						
Common						
Non Utility Property	179,120.94	-	-	-	-	179,120.94
Total 121001	179,120.94	-	-	-	-	179,120.94
107 **Construction Work In Progress**						
Electric						
Electric	954,430,277.48	(671,834,497.22)	-	-	(671,834,497.22)	282,595,780.26
Total 107001	954,430,277.48	(671,834,497.22)	-	-	(671,834,497.22)	282,595,780.26
Total Plant (Non-CWIP)	5,542,530,138.85	738,759,611.08	(13,640,391.95)	-	725,119,219.13	6,267,649,357.98
Total Plant + CWIP	6,496,960,416.33	66,925,113.86	(13,640,391.95)	-	53,284,721.91	6,550,245,138.24
Total Plant + CWIP - Nonutility (BS)	$ 6,496,781,295.39	$ 66,925,113.86	$ (13,640,391.95)	$ -	$ 53,284,721.91	$ 6,550,066,017.30

May 26, 2011

Kentucky Utilities Company
Summary of Utility Plant - Reserve for Depreciation of Utility Plant
April 30, 2011

	Beginning Balance	Accruals	Retirements	Transfers/ Adjustments	ARO Settlements	RWIP Transfers Out	Cost of Removal	Salvage	Other Credits	Ending Balance
Life Reserve										
Electric Distribution.....................................	$ (398,692,068.83)	$ (9,130,832.10)	$ 6,327,436.63	$ (181,198.53)	$ -	$ -	$ -	$ -	$ -	$ (401,676,662.83)
Electric Distribution - ARO..........................	(790.87)	(1,477.80)	-	-	-	-	-	-	-	(2,268.67)
Electric General Plant..................................	(57,721,732.75)	(1,926,231.15)	4,012,536.85	181,198.53	-	-	-	-	-	(55,454,228.52)
Electric Hydro Production............................	(7,765,077.65)	(39,568.26)	15,190.72	-	-	-	-	-	-	(7,789,455.19)
Electric Hydro Production - ARO................	(121.57)	(324.32)	-	-	-	-	-	-	-	(445.89)
Electric Other Production.............................	(160,412,820.60)	(5,568,372.87)	59,784.69	-	-	-	-	-	-	(165,921,408.78)
Electric Other Production - ARO.................	(84.76)	(226.28)	-	-	-	-	-	-	-	(311.04)
Electric Steam Production............................	(1,067,997,942.05)		2,573,751.38	-	-	-	-	-	-	(1,094,487,336.28)
Electric Steam Production - ARO................	(485,952.30)	(998,431.12)	25,296.16	-	-	-	-	-	-	(1,459,087.26)
Electric Transmission...................................	(211,361,531.11)	(3,064,914.47)	407,344.55	-	-	-	-	-	-	(214,019,101.03)
Electric Transmission - ARO.......................	(156.99)	(418.80)	-	-	-	-	-	-	-	(575.79)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(1,904,438,279.48)	(49,793,942.78)	13,421,340.98	-	-	-	-	-	-	(1,940,810,881.28)
Cost of Removal										
Electric Distribution.....................................	(195,818,054.42)	(2,670,077.76)	-	0.02	-	-	733,642.99	-	-	(197,754,489.17)
Electric General Plant..................................	207,510.70	(14,655.26)	-	(0.02)	-	-	12,732.10	-	-	205,587.52
Electric Hydro Production............................	(374,056.75)	(1,733.36)	-	-	-	-	29,260.00	-	-	(346,530.11)
Electric Other Production.............................	(3,174,464.89)	(298,377.64)	-	-	-	-	1,251.94	-	-	(3,471,590.59)
Electric Steam Production............................	(113,988,699.33)	(8,133,969.14)	-	-	-	-	799,643.71	-	-	(121,323,024.76)
Electric Transmission...................................	(137,175,896.62)	(924,443.01)	-	-	-	-	696,310.08	-	-	(137,404,029.55)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(450,323,661.31)	(12,043,256.17)	-	-	-	-	2,272,840.82	-	-	(460,094,076.66)
Salvage										
Electric Distribution.....................................	48,221,606.07	651,008.63	-	-	-	-	-	(89,343.17)	-	48,783,271.53
Electric General Plant..................................	149,758.57	-	-	-	-	-	-	-	-	149,758.57
Electric Hydro Production............................	46,518.69	-	-	-	-	-	-	-	-	46,518.69
Electric Other Production.............................	618,891.61	-	-	-	-	-	-	-	-	618,891.61
Electric Steam Production............................	20,938,580.66	1,558,779.88	-	-	-	-	-	(1,116,553.50)	-	21,380,807.04
Electric Transmission...................................	23,009,336.80	214,700.33	-	-	-	-	-	(1,555.65)	-	23,222,481.48
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	92,984,692.40	2,424,488.84	-	-	-	-	-	(1,207,452.32)	-	94,201,728.92
Total Reserves										
Electric Distribution.....................................	(546,288,517.18)	(11,149,901.23)	6,327,436.63	(181,198.51)	-	-	733,642.99	(89,343.17)	-	(550,647,880.47)
Electric Distribution - ARO..........................	(790.87)	(1,477.80)	-	-	-	-	-	-	-	(2,268.67)
Electric General Plant..................................	(57,364,463.48)	(1,940,886.41)	4,012,536.85	181,198.51	-	-	12,732.10	-	-	(55,098,882.43)
Electric Hydro Production............................	(8,092,615.71)	(41,301.62)	15,190.72	-	-	-	29,260.00	-	-	(8,089,466.61)
Electric Hydro Production - ARO................	(121.57)	(324.32)	-	-	-	-	-	-	-	(445.89)
Electric Other Production.............................	(162,968,393.88)	(5,866,750.51)	59,784.69	-	-	-	1,251.94	-	-	(168,774,107.76)
Electric Other Production - ARO.................	(84.76)	(226.28)	-	-	-	-	-	-	-	(311.04)
Electric Steam Production............................	(1,161,048,060.72)	(35,638,334.87)	2,573,751.38	-	-	-	799,643.71	(1,116,553.50)	-	(1,194,429,554.00)
Electric Steam Production - ARO................	(485,952.30)	(998,431.12)	25,296.16	-	-	-	-	-	-	(1,459,087.26)
Electric Transmission...................................	(325,528,090.93)	(3,774,657.15)	407,344.55	-	-	-	696,310.08	(1,555.65)	-	(328,200,649.10)
Electric Transmission - ARO.......................	(156.99)	(418.80)	-	-	-	-	-	-	-	(575.79)
Non Utility Property.....................................	-	-	-	-	-	-	-	-	-	-
	(2,261,777,248.39)	(59,412,710.11)	13,421,340.98	-	-	-	2,272,840.82	(1,207,452.32)	-	(2,306,703,229.02)
Retirement Work in Process										
Electric..	13,605,672.01		-	14,675.52	(42,353.83)	(1,023,034.67)	3,965,849.64	(244,563.61)	(131,860.52)	16,144,384.54
	13,605,672.01	-	-	14,675.52	(42,353.83)	(1,023,034.67)	3,965,849.64	(244,563.61)	(131,860.52)	16,144,384.54
YTD ACTIVITY	(2,248,171,576.38)	(59,412,710.11)	13,421,340.98	14,675.52	(42,353.83)	(1,023,034.67)	6,238,690.46	(1,452,015.93)	(131,860.52)	(2,290,558,844.48)
Amortization										
Electric..	(13,755,205.98)	(2,300,264.40)	219,050.97	-	-	-	-	-	-	(15,836,419.41)
	(13,755,205.98)	(2,300,264.40)	219,050.97	-	-	-	-	-	-	(15,836,419.41)
Depreciation & Amortization Total										
Depreciation & Amortization Total...............	(2,261,926,782.36)	(61,712,974.51)	13,640,391.95	14,675.52	(42,353.83)	(1,023,034.67)	6,238,690.46	(1,452,015.93)	(131,860.52)	(2,306,395,263.89)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)..............	$ 4,234,854,513.03									$ 4,243,670,753.41

May 26, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of April 30, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 107,312,923.69	$ -	$ 107,312,923.69
Rate Refunds	-	-	-
Total Operating Revenues	107,312,923.69	-	107,312,923.69
Fuel for Electric Generation	32,088,589.82	-	32,088,589.82
Power Purchased	11,778,662.25	-	11,778,662.25
Other Operation Expenses	17,821,259.16	-	17,821,259.16
Maintenance	15,523,681.30	-	15,523,681.30
Depreciation	15,165,884.45	99.15	15,165,983.60
Amortization Expense	587,302.91	-	587,302.91
Regulatory Credits	(495,970.94)	-	(495,970.94)
Taxes			
Federal Income	2,025,840.91	-	2,025,840.91
State Income	369,454.26	-	369,454.26
Deferred Federal Income - Net	-	(22,508.21)	(22,508.21)
Deferred State Income - Net	-	(4,104.84)	(4,104.84)
Property and Other	2,501,068.96	-	2,501,068.96
Investment Tax Credit	-	-	-
Amortization of Investment Tax Credit	-	-	-
Loss (Gain) from Disposition of Allowances	-	-	-
Accretion Expense	227,486.03	-	227,486.03
Total Operating Expenses	97,593,259.11	(26,513.90)	97,566,745.21
Net Operating Income	9,719,664.58	26,513.90	9,746,178.48
Other Income Less Deductions			
Amortization of Investment Tax Credit	233,343.00	-	233,343.00
Other Income Less Deductions	(523,257.23)	(73,840.35)	(597,097.58)
AFUDC - Equity	2,587.63	-	2,587.63
Total Other Income Less Deductions	(287,326.60)	(73,840.35)	(361,166.95)
Income Before Interest Charges	9,432,337.98	(47,326.45)	9,385,011.53
Interest on Long-Term Debt	5,157,059.19	(5,525.50)	5,151,533.69
Amortization of Debt Expense - Net	293,849.87	-	293,849.87
Other Interest Expenses	507,098.74	-	507,098.74
AFUDC - Borrowed Funds	(786.20)	-	(786.20)
Total Interest Charges	5,957,221.60	(5,525.50)	5,951,696.10
Net Income	$ 3,475,116.38	$ (41,800.95)	$ 3,433,315.43

Note: Purchase accounting is subject to change through October 31, 2011

May 26, 2011

Kentucky Utilities Company
Statement of Income with Purchase Accounting
As of April 30, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 512,738,145.39	$ -	$ 512,738,145.39
Rate Refunds	-	-	-
Total Operating Revenues	512,738,145.39	-	512,738,145.39
Fuel for Electric Generation	163,332,946.85	-	163,332,946.85
Power Purchased	45,350,062.54	-	45,350,062.54
Other Operation Expenses	75,121,902.28	31,612.30	75,153,514.58
Maintenance	40,383,458.40	-	40,383,458.40
Depreciation	59,347,504.46	(7.34)	59,347,497.12
Amortization Expense	2,300,264.40	-	2,300,264.40
Regulatory Credits	(1,905,095.86)	-	(1,905,095.86)
Taxes			
Federal Income	9,114,390.71	-	9,114,390.71
State Income	3,176,438.12	-	3,176,438.12
Deferred Federal Income - Net	22,131,675.83	(27,419.95)	22,104,255.88
Deferred State Income - Net	1,776,808.83	(5,000.60)	1,771,808.23
Property and Other	9,240,239.81	-	9,240,239.81
Investment Tax Credit	-	-	-
Amortization of Investment Tax Credit	-	-	-
Loss (Gain) from Disposition of Allowances	(3,293.39)	-	(3,293.39)
Accretion Expense	904,217.54	-	904,217.54
Total Operating Expenses	430,271,520.52	(815.59)	430,270,704.93
Net Operating Income	82,466,624.87	815.59	82,467,440.46
Other Income Less Deductions			
Amortization of Investment Tax Credit	819,661.00	-	819,661.00
Other Income Less Deductions	234,268.79	1,058,290.16	1,292,558.95
AFUDC - Equity	7,519.53	-	7,519.53
Total Other Income Less Deductions	1,061,449.32	1,058,290.16	2,119,739.48
Income Before Interest Charges	83,528,074.19	1,059,105.75	84,587,179.94
Interest on Long-Term Debt	20,535,741.78	(22,101.97)	20,513,639.81
Amortization of Debt Expense - Net	1,165,690.29	-	1,165,690.29
Other Interest Expenses	1,940,437.91	-	1,940,437.91
AFUDC - Borrowed Funds	(2,281.77)	-	(2,281.77)
Total Interest Charges	23,639,588.21	(22,101.97)	23,617,486.24
Net Income	$ 59,888,485.98	$ 1,081,207.72	$ 60,969,693.70

Note: Purchase accounting is subject to change through October 31, 2011

May 26, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of April 30, 2011

Retained Earnings and Undistributed Earnings	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,463,485,376.42	$ 15,711,982.75	$ (1,402,655,522.06)	$ (14,610,021.49)	$ 60,829,854.36	$ 1,101,961.26
Add						
Net Income for Period..	3,475,116.38	-	(41,800.95)	-	3,433,315.43	-
Deductions:						
Adjust for Equity in Subsidiary						
Earnings for Year						
EE Inc..	522,500.00	(522,500.00)	73,840.35	(73,840.35)	596,340.35	(596,340.35)
Dividends Received Current Year						
EE Inc..	-	-	-	-	-	-
Balance at End of Period	1,467,482,992.80	15,189,482.75	(1,402,623,482.66)	(14,683,861.84)	64,859,510.14	505,620.91
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings................		15,189,482.75		(14,683,861.84)		505,620.91
Statutory Tax Rate...		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary.........................		$ 5,908,708.79		$ (5,712,022.26)		$ 196,686.53

Note: Purchase accounting is subject to change through October 31, 2011.

May 26, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of April 30, 2011

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Combined	
Retained Earnings and Undistributed Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings	Retained Earnings	Undistributed Subsidiary Earnings
Balance at Beginning of Period.......................................	$ 1,439,351,593.82	$ 14,432,395.75	$ (1,404,000,051.78)	$ (14,388,500.44)	$ 35,351,542.04	$ 43,895.31
Add						
Net Income for Period ……………………………	59,888,485.98	-	1,081,207.72	-	60,969,693.70	-
Deductions:						
Common Dividends						
Common Stock Without Par Value....................	(31,000,000.00)	-	-	-	(31,000,000.00)	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc………………………..…………	(757,087.00)	757,087.00	295,361.40	(295,361.40)	(461,725.60)	461,725.60
Dividends Received Current Year						
EE Inc……………………………………	-	-	-	-	-	-
Balance at End of Period …...……………………………	1,467,482,992.80	15,189,482.75	(1,402,623,482.66)	(14,683,861.84)	64,859,510.14	505,620.91
Deferred Taxes Related to Undistributed Subsidiary Earnings						
Balance of Undistributed Subsidiary Earnings…………		15,189,482.75		(14,683,861.84)		505,620.91
Statutory Tax Rate…...…………………………………		38.9%		38.9%		38.9%
Deferred Taxes on Equity in Subsidiary…...………………		$ 5,908,708.79		$ (5,712,022.26)		$ 196,686.53

Note: Purchase accounting is subject to change through October 31, 2011

May 26, 2011

Kentucky Utilities Company
Analysis of Retained Earnings with Purchase Accounting
As of April 30, 2011

Retained Earnings and Undistributed Earnings	Year Ended Current Month without Purchase Accounting: Retained Earnings	Year Ended Current Month without Purchase Accounting: Undistributed Subsidiary Earnings	Year Ended Current Month to Date Purchase Accounting: Retained Earnings	Year Ended Current Month to Date Purchase Accounting: Undistributed Subsidiary Earnings	Year Ended Current Month Combined: Retained Earnings	Year Ended Current Month Combined: Undistributed Subsidiary Earnings
Balance at Beginning of Period......................................	$ 1,367,700,691.90	$ 13,218,468.75	$ -	$ -	$ 1,367,700,691.90	$ 13,218,468.75
Add						
Net Income for Period...	182,753,314.90	-	1,017,042.10	-	183,770,357.00	-
Purchase Accounting Deductions:	-	-	(1,404,083,566.85)	(14,240,819.75)	(1,404,083,566.85)	(14,240,819.75)
Deductions:						
Common Dividends						
Common Stock Without Par Value..................	(81,000,000.00)	-	-	-	(81,000,000.00)	-
Adjust for Equity in Subsidiary Earnings for Year						
EE Inc...	(1,971,014.00)	1,971,014.00	443,042.09	(443,042.09)	(1,527,971.91)	1,527,971.91
Dividends Received Current Year						
EE Inc...	-	-	-	-	-	-
Balance at End of Period	1,467,482,992.80	15,189,482.75	(1,402,623,482.66)	(14,683,861.84)	64,859,510.14	505,620.91

Deferred Taxes Related to Undistributed Subsidiary Earnings	Without Purchase Accounting: Undistributed Subsidiary Earnings	To Date Purchase Accounting: Undistributed Subsidiary Earnings	Combined: Undistributed Subsidiary Earnings
Balance of Undistributed Subsidiary Earnings................	15,189,482.75	(14,683,861.84)	505,620.91
Statutory Tax Rate...	38.9%	38.9%	38.9%
Deferred Taxes on Equity in Subsidiary.........................	5,908,708.79	(5,712,022.26)	196,686.53

Combined Balance of Retained Earnings	12 MONTHS 04/30/11	12 MONTHS 4/30/2010
Retained Earnings at Beginning of Period.......................	1,380,919,160.65	1,211,647,960.38
Net Income for Period	183,770,357.00	169,271,200.27
FIN 48 Adjustment..	-	-
Subtotal..	1,564,689,517.65	1,380,919,160.65
Deduct		
Purchase Accounting Adjustment.............................	1,404,083,566.85	-
Dividends on Common Stock...................................	81,000,000.00	-
Retained Earnings at End of Period...............................	$ 79,605,950.80	$ 1,380,919,160.65

Note: Purchase accounting is subject to change through October 31, 2011

May 26, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of April 30, 2011

Assets	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Utility Plant			
Utility Plant at Original Cost......................................	$ 6,550,066,017.30	$ (1,889,815,635.70)	$ 4,660,250,381.60
Less Reserves for Depreciation and Amortization......	2,306,395,263.89	(1,889,815,643.04)	416,579,620.85
Total...	4,243,670,753.41	7.34	4,243,670,760.75
Investments			
Electric Energy, Inc..	12,399,562.55	17,278,640.91	29,678,203.46
Ohio Valley Electric Corporation...............................	250,000.00	-	250,000.00
Nonutility Property - Less Reserve............................	179,120.94	-	179,120.94
Special Funds...	-	-	-
Total...	12,828,683.49	17,278,640.91	30,107,324.40
Current and Accrued Assets			
Cash...	31,010,711.31	-	31,010,711.31
Special Deposits...	747,761.07	-	747,761.07
Temporary Cash Investments...................................	25,009,882.51	-	25,009,882.51
Accounts Receivable-Less Reserve..........................	146,865,268.36	-	146,865,268.36
Notes Receivable from Assoc Companies...............	-	-	-
Accounts Receivable from Assoc Companies..........	-	-	-
Materials & Supplies-At Average Cost			
Fuel..	96,058,692.86	-	96,058,692.86
Plant Materials & Operating Supplies....................	33,092,118.40	-	33,092,118.40
Stores Expense...	9,379,577.69	-	9,379,577.69
Allowance Inventory..	530,898.99	-	530,898.99
Prepayments...	7,953,538.67	-	7,953,538.67
Miscellaneous Current & Accrued Assets................	119,965.13	-	119,965.13
Total...	350,768,414.99	-	350,768,414.99
Deferred Debits and Other			
Unamortized Debt Expense..	21,001,779.68	(4,554,200.19)	16,447,579.49
Unamortized Loss on Bonds......................................	12,178,432.49	-	12,178,432.49
Accumulated Deferred Income Taxes........................	95,312,656.15	75,035,179.20	170,347,835.35
Deferred Regulatory Assets..	278,119,589.05	19,325,628.75	297,445,217.80
Other Deferred Debits..	44,182,569.04	171,979,310.22	216,161,879.26
Goodwill..	-	607,404,368.23	607,404,368.23
Total...	450,795,026.41	869,190,286.21	1,319,985,312.62
Total Assets...	$ 5,058,062,878.30	$ 886,468,934.46	$ 5,944,531,812.76

Note: Purchase accounting is subject to change through October 31, 2011

May 26, 2011

Kentucky Utilities Company
Balance Sheet with Purchase Accounting
As of April 30, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting Adjustments	Total
Proprietary Capital			
Common Stock...	$ 308,139,977.56	$ -	$ 308,139,977.56
Less: Common Stock Expense.....................................	321,288.87	-	321,288.87
Paid-In Capital...	315,858,083.00	2,032,588,750.94	2,348,446,833.94
Other Comprehensive Income.....................................	(2,494,086.95)	1,990,823.26	(503,263.69)
Retained Earnings..	1,467,482,992.80	(1,402,623,482.66)	64,859,510.14
Unappropriated Undistributed Subsidiary Earnings....	15,189,482.75	(14,683,861.84)	505,620.91
Total Proprietary Capital..	2,103,855,160.29	617,272,229.70	2,721,127,389.99
Pollution Control Bonds - Net of Reacquired Bonds...	350,779,405.00	1,128,302.05	351,907,707.05
First Mortgage Bonds...	1,489,388,656.25	-	1,489,388,656.25
Total Long-Term Debt...	1,840,168,061.25	1,128,302.05	1,841,296,363.30
Total Capitalization..	3,944,023,221.54	618,400,531.75	4,562,423,753.29
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Notes Payable...	-	-	-
Accounts Payable..	71,282,791.92	-	71,282,791.92
Accounts Payable to Associated Companies................	41,019,000.60	-	41,019,000.60
Customer Deposits...	22,926,426.59	-	22,926,426.59
Taxes Accrued..	13,958,987.99	-	13,958,987.99
Interest Accrued...	28,616,817.96	-	28,616,817.96
Miscellaneous Current and Accrued Liabilities...........	21,209,081.21	-	21,209,081.21
Total...	199,013,106.27	-	199,013,106.27
Deferred Credits and Other			
Accumulated Deferred Income Taxes..........................	482,369,779.76	81,317,663.93	563,687,443.69
Investment Tax Credit...	103,274,508.32	-	103,274,508.32
Regulatory Liabilities..	115,217,224.39	171,979,310.22	287,196,534.61
Customer Advances for Construction..........................	2,870,420.89	-	2,870,420.89
Asset Retirement Obligations......................................	54,827,128.69	-	54,827,128.69
Other Deferred Credits...	17,527,358.73	14,771,428.56	32,298,787.29
Miscellaneous Long-Term Liabilities...........................	2,384,017.09	-	2,384,017.09
Accum Provision for Postretirement Benefits.............	136,556,112.62	-	136,556,112.62
Total...	915,026,550.49	268,068,402.71	1,183,094,953.20
Total Liabilities and Stockholders' Equity.........................	$ 5,058,062,878.30	$ 886,468,934.46	$ 5,944,531,812.76

Note: Purchase accounting is subject to change through October 31, 2011

May 26, 2011