Louisville Gas and Electric Company
Case No. 2012-00222
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:

LG&E's gas and electric rates must be adjusted to a level which will provide it with an opportunity to recover sufficient revenues to operate its gas and electric businesses successfully, maintain its financial integrity, attract capital and compensate investors for the risks assumed with respect to its gas and electric businesses. LG&E's electric and gas operations are under-earning. Its gas and electric plant dedicated to the service of customers has increased since its last rate cases. Despite ongoing and significant efforts to manage costs and the implementation of operational efficiencies, its operation and maintenance costs have increased. LG&E's current rates do not provide sufficient revenue to pay the expenses of its gas and electric operations and also provide a fair and reasonable return on its capital. The rates presently charged by LG&E for gas and electric service are no longer compensatory and are unfair, unjust and unreasonable. LG&E now seeks an increase in both gas and electric 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, John Clay Murphy, and Robert M. Conroy.

In addition, LG&E is proposing to replace and assume ownership of certain gas risers and service lines currently owned by customers. LG&E's application requests the Commission to issue a certificate of public convenience and necessity for LG&E's proposed Gas Line Program. LG&E is proposing a gas line tracker to recover the costs associated with the Gas Line Program as part of its adjustment to gas rates. Please refer to the testimonies of Chris Hermann, and Lonnie E. Bellar for the details of the Gas Line Program and gas line tracker.

Louisville Gas and Electric Company
Case No. 2012-00222
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:

LG&E 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).

Louisville Gas and Electric Company
Case No. 2012-00222
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 LG&E'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).

Louisville Gas and Electric Company
Case No. 2012-00222
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:

LG&E is not a limited partnership and, therefore, compliance with this filing requirement is not necessary.

Louisville Gas and Electric Company
Case No. 2012-00222
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: 125643
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,

LOUISVILLE GAS AND ELECTRIC COMPANY

is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is July 2, 1913 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.

Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
125643/0032196

Louisville Gas and Electric Company
Case No. 2012-00222
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 LG&E is Louisville Gas and Electric Company. It has never done business in any state under an assumed name and has never filed a Certificate of Assumed Name as may be required by KRS 365.015. Therefore, the filing of a copy of any such certificate as required by this Filing Requirement is not necessary.

Louisville Gas and Electric Company
Case No. 2012-00222
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.

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

In the nine counties of the Louisville, Kentucky, metropolitan area
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

Louisville Gas and Electric Company

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, Louisville, Kentucky

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

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DSM	Demand-Side Management Cost Recovery Mechanism	86	04-01-12	
ECR	Environmental Cost Recovery Surcharge	87	08-01-12	T
FF	Franchise Fee Rider	90	10-16-03	
ST	School Tax	91	08-01-10	
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SECTION 5 – Terms and Conditions				
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	General	96	02-06-09	
	Customer Responsibilities	97	08-01-12	T
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	Character of Service	99	08-01-10	
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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.

RATE

Basic Service Charge:	$13.00 per month	I
Plus an Energy Charge of:	$ 0.07513 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.

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:	$ 0.07513 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

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, Louisville, 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 T
maximum loads do not exceed 50 kW. Existing customers with 12-month-average maximum T
monthly loads exceeding 50 kW who are receiving service under P.S.C. Electric No. 6, Fourth T
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 T
elects to take service under another rate schedule, Customer may not again take service under T
this rate schedule unless and until Customer meets the Availability requirements that would apply T
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:	$ 0.08624 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.

T

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.

Standard Rate **PS**
Power Service Rate

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 P.S.C. of Ky. Electric No. 6, Fourth Revision of Original Sheet No. 15, Large Commercial Rate LC, and Fourth Revision of Original Sheet No. 25, Large Power Industrial Rate LP, 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:	$ 0.03615	$ 0.03416	I
Plus a Demand Charge per kW of:			
Summer Rate: (Five Billing Periods of May through September)	$16.20	$ 13.54	I
Winter Rate: (All other months)	$13.75	$ 11.31	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 load expected on the system or 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, Louisville, Kentucky

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 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.

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.

RATE

Basic Service Charge per month:	$200.00
Plus an Energy Charge per kWh of:	$ 0.03580
Plus a Maximum Load Charge per kW of:	
Peak Demand Period	$ 6.15
Intermediate Demand Period	$ 4.52
Base Demand Period	$ 4.00

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.

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, 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)

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

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** N

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 maximum of 75,000 kVA by up to 2,000kVA per year or in greater increments with approval of Company's transmission operator.

RATE

Basic Service Charge per month:	$300.00
Plus an Energy Charge per kWh of:	$ 0.03028
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 5.59
Intermediate Demand Period	$ 3.95
Base Demand Period	$ 3.72

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

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 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, 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, Louisville, Kentucky

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. T
Existing customers may increase loads to a 12-month-average monthly maximum of 75,000 T
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:	$ 0.03228	I
Plus a Maximum Load Charge per kVA of:		
Peak Demand Period	$ 4.64	I
Intermediate Demand Period	$ 3.03	I
Base Demand Period	$ 2.76	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

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 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 **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 FLS schedule of Kentucky Utilities 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:	$ 0.03228	$ 0.03228	I
Plus a Maximum Load Charge per kVA of:			
Peak Demand Period	$ 3.03	$ 3.03	I
Intermediate Demand Period	$ 1.92	$ 1.92	I
Base Demand Period	$ 1.90	$ 1.15	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 T

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.

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, Louisville, Kentucky**

ADJUSTMENT CLAUSES

The 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.

TERM OF CONTRACT

Unless terminated by mutual agreement, the initial term of contract for service shall be for a fixed term of five (5) years with successive one (1) 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 T
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 CSR30. 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 LG&E T and KU. 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**

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. T

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	
High Pressure Sodium					T
452	Cobra Head	16,000	0.181	$12.48	N
453	Cobra Head	28,500	0.294	14.57	N
454	Cobra Head	50,000*	0.471	16.58	N
455	Directional	16,000	0.181	$13.44	N
456	Directional	50,000*	0.471	17.41	N
457	Open Bottom	9,500	0.117	$10.60	N
Metal Halide					T
470	Directional	12,000	0.150	$12.47	T/I
473	Directional	32,000	0.350	18.09	T/I
476	Directional	107,800*	1.080	37.80	T/I

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. T

Standard Rate **LS**
Lighting Service

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. For poles installed prior to 8/1/2010, such charge for each pole and span of secondary installed after 6/30/2004 and used in providing a light offered under LS as listed under RLS Sheet No. 36, Bill Code 958, and such charge for each pole and span of secondary installed prior to 6/30/2004 and used in providing a light offered under LS as listed under RLS Sheet No. 36, Bill Code 900. T

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. T

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth	Monthly Charge Historic Fluted	
High Pressure Sodium							T
412	Colonial, 4-Sided	5,800	0.083		$19.74		T/I
413	Colonial, 4-Sided	9,500	0.117		20.37		T/I
415	Acorn	5,800	0.083		$20.13		T/I
416	Acorn	9,500	0.117		22.48		T/I
427	London	5,800	0.083			$35.40	T/I
429	London	9,500	0.117			36.21	T/I
431	Victorian	5,800	0.083			$33.10	T/I
433	Victorian	9,500	0.117			35.12	T/I
						Westchester/Norfolk	T
956	Victorian/London Bases					$ 3.61	N
423	Cobra Head	16,000	0.181		$26.23		T/I
424	Cobra Head	28,500	0.294		28.14		T/I
425	Cobra Head	50,000*	0.471		33.50		T/I
439/420	Contemporary	16,000	0.181	$16.18	$29.83		T/I
440/421	Contemporary	28,500*	0.294	17.81	32.62		T/I
441/422	Contemporary	50,000*	0.471	21.59	37.93		T/I
400	Dark Sky	4,000	0.060		$23.82		T/I
401	Dark Sky	9,500	0.117		24.86		T/I
Metal Halide							T
479/480	Contemporary	12,000	0.150	$13.76	$23.69		T/I
481/482	Contemporary	32,000	0.350	19.90	29.81		T/I
483/484	Contemporary	107,800*	1.080	40.81	50.71		T/I

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. T

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.

TERMS AND CONDITIONS (continued)

T

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**

Restricted Lighting Service

T

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE T

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 composing 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).

RATE T

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Fixture Only	Monthly Charge: Fixture & Wood Pole	Monthly Charge: Fixture & Orn. Pole	
Mercury Vapor							T
252	Cobra/Open Bottom	8,000	0.210	$ 9.20			N
458	Cobra Head	8,000	0.210	$10.80			T/I
203	Cobra Head	13,000	0.298	10.45			N
204	Cobra Head	25,000	0.462	12.71			N
209	Cobra Head	60,000	1.180	25.70			N
207	Directional	25,000	0.462	$14.78			N
210	Directional	60,000	1.180	26.92			N
201	Open Bottom	4,000	0.100	$ 7.94			N
Metal Halide							T
471	Directional	12,000	0.150		$14.79	N/A	T/I
474/475	Directional	32,000	0.350		20.42	27.99	T/I
477	Directional	107,800	1.080		41.03	N/A	T/I
Wood Pole							T
958	Installed Before 3/1/2010			$11.49			T/I
900	Installed Before 7/1/2004			2.09			T/I

Standard Rate **RLS**
Restricted Lighting Service

UNDERGROUND SERVICE T
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. T T T

RATE T

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth	
						T
High Pressure Sodium						T
275	Cobra/Contemporary	16,000	0.181		$24.74	N
266	Cobra/Contemporary	28,500	0.294		27.03	N
267	Cobra Contemporary	50,000	0.471		30.83	N
276	Coach/Acorn	5,800	0.083		$14.01	N
274	Coach/Acorn	9,500	0.1117		17.00	N
277	Coach/Acorn	16,000	0.181		21.97	N
279/278	Contemporary	120,000	1.000	$39.51	$71.15	N
417	Acorn, Bronze	9,500	0.117		$23.61	T/I
419	Acorn, Bronze	16,000	0.180		24.50	T/I
280	Victorian	5,800	0.083	$19.30		N
281	Victorian	9,500	0.117	20.22		N
282	London	5,800	0.083	$19.46		N
283	London	9,500	0.117	20.69		N
426	London	5,800	0.083		$33.39	T/I
428	London	9,500	0.117		34.20	T/I
430	Victorian	5,800	0.083		32.41	T/I
432	Victorian	9,500	0.117		34.44	T/I
Victorian/London Bases						T
950	Old Town				$ 3.52	N
951	Chesapeake				3.80	N
Poles						T
901	10" Smooth Pole				10.99	N
902	10" Fluted Pole				13.11	N

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, Louisville, Kentucky**

UNDERGROUND SERVICE (continued) T

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth	
						T
Mercury Vapor						T
318	Cobra Head	8,000	0.210		$17.18	N
314	Cobra Head	13,000	0.298		18.82	N
315	Cobra Head	25,000	0.462		22.31	N
347	Cobra (State of KY Pole)	25,000	0.462	$22.30		T/I
206	Coach	4,000	0.100		$12.33	N
208	Coach	8,000	0.210		13.95	N
Incandescent						T
349	Continental Jr.	1,500	0.102		$ 8.86	T/I
348	Continental Jr.	6,000	0.447		12.38	T/I

Where Customer's location required the installation of additional facilities, Company may have furnished the requested facilities at an additional charge per month to be determined under the Excess Facilities Rider. T

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 T

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. 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
$0.05942 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
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 types of equipment served.

2. 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:	$0.07178 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, Louisville, Kentucky

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
$9.42 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:

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 Louisville Gas and Electric 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 Louisville Gas and Electric Company. This insurance may not be canceled for any cause without sixty (60) days advance written notice being first given to Louisville Gas and Electric 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. T

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

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. If both gas and electric services are reconnected at the same time, the total charge for restoration of both services shall be $28.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection. R R

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. R

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. 9, CSR10 and CSR30 for Louisville Gas and Electric Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric 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 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 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 T 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.

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. 9, CSR10 and CSR30 for Louisville Gas and Electric Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric 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 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.

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. T

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

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, $C_{LG\&E}$ 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:
   $D_1 \leq C_{LG\&E}$; $CAP_i = 0$

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:

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

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

   $D_i > [C_{LG\&E} + C_{QF}]$; $CAP_i = C_{QF}$

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.

<u>Level 1</u> – 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.

<u>Level 2</u> – 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:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E 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:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E 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: ________________

Standard Rate Rider **EF**
Excess Facilities

APPLICABILITY

In all territory served.

AVAILABILITY OF SERVICE

This rider is available for non-standard 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. T

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 dedicated to a specific customer. Applications of excess facilities include, but are not limited to, emergency backup feeds, automatic transfer switches, redundant transformer capacity, and duplicate or check meters. T T

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 in the monthly charge for a replacement of facilities will be made during the initial five (5) year term of contract. T T T

Customer shall pay for excess facilities by: T

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

Percentage With No Contribution-in-Aid-of-Construction	1.37%	T/R

(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: T T T

Percentage with Contribution-in-Aid-of-Construction	0.55%	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, Louisville, Kentucky

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 Customer's facility in the event that an emergency or unusual occurrence renders 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	$1.13 per kW/kVA per Month	R/T
Primary Distribution	$0.88 per kW/kVA per Month	R/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 (1) 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:	$13.14	$12.50	$11.28	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 T
rate on which Customer is billed) is exceeded by a recorded demand, such recorded demand T
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 Customer contracted.

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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 the 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 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 therefore 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

Standard Rate Rider

Kilowatt-Hours Consumed By Lighting Units T

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 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 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, Louisville, 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, 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 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 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

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. T

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 kW as is appropriate) 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 (or kW as is appropriate); and
    2) existing customers contracting for a minimum annual average of monthly billing load of 1,000 kVA (or kW as is appropriate) 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:	$ 0.05235 per kWh	I
Intermediate Hours:	$ 0.07335 per kWh	I
Peak Hours:	$ 0.13951 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, Louisville, Kentucky**

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.

Adjustment Clause **FAC**

Fuel Adjustment Clause

APPLICABLE.
In all territory service.

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

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(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 $0.02215 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. 2010-00493 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 Rate VFD, General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, Retail Transmission Service Rate RTS, 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."

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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, and LEV customer classes is defined as the weighted average price per kWh of expected

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RATE (continued)

billings under the energy charges contained in the RS, VFD, GS, 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. T T

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 thirty-six (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, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Low Emission Vehicle Service Rate shall be divided by the expected kilowatt-hour sales for the T T T 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. T

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

The filing of modifications to the DSMRC that require changes in the DCR component shall be made at least two months prior to the beginning of the effective period for billing.

Modifications to other components of the DSMRC shall be made at least thirty (30) 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 LG&E'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.

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

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 LG&E 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. LG&E 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, PS, TODS, TODP, and RTS Standard Electric Rate Schedules. T

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. T

- 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:

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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.

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 50 kW demand reduction per control event. The Company will continue to enroll program participants until 10MW curtailable load is achieved. T

- $25 per kW for verified load reduction during June, July, August, & September. T
- 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 Rate RS, Volunteer Fire Department Rate VFD, and Low Emission Vehicle Service Rate LEV	Energy Charge	T
DSM Cost Recovery Component (DCR)	$ 0.00147 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00154 per kWh	
DSM Incentive (DSMI)	$ 0.00007 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00049 per kWh	
DSM Balance Adjustment (DBA)	$ (0.00070) per kWh	
Total DSMRC for Rates RS, VFD, and LEV	$ 0.00287 per kWh	

General Service Rate GS	Energy Charge	
DSM Cost Recovery Component (DCR)	$ 0.00076 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00158 per kWh	
DSM Incentive (DSMI)	$ 0.00004 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00007 per kWh	
DSM Balance Adjustment (DBA)	$ (0.00004) per kWh	
Total DSMRC for Rates GS	$ 0.00241 per kWh	T

Commercial Customers Served Under Power Service Rate PS	Energy Charge	T
DSM Cost Recovery Component (DCR)	$ 0.00025 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00084 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 Rate PS	$ 0.00111 per kWh	

Commercial Customers Served Under Time-of-Day Secondary Service Rate TODS and Time-of-Day Primary Service Rate TODP	Energy Charge	T T
DSM Cost Recovery Component (DCR)	$ 0.00022 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00070 per kWh	
DSM Incentive (DSMI)	$ 0.00001 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per kWh	
DSM Balance Adjustment (DBA)	$ (0.00004) per kWh	
Total DSMRC for Rates TODS, and TODP	$ 0.00089 per kWh	T

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

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	T
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	T

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

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.

$$\text{Group Environmental Surcharge Billing Factor} = \text{Group } E(m) / \text{Group } R(m)$$

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, Louisville, Kentucky

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.

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.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

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 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 months.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

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 customers 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 its customers 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 the 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 contracted 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 the 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, Customer shall obtain from the property owner or owners the necessary consent to the installation and maintenance in said premises and in or about such intervening property of

TERMS AND CONDITIONS

Customer Responsibilities

PERMITS (continued)

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 the 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 with 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 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

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).

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, Louisville, Kentucky

TERMS AND CONDITIONS

Character of Service

Electric service, under the rate schedule 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 three-wire service where network system is available.
2) Three phase 240 volts three-wire, 480 volts three-wire service, 120/208Y volts four-wire service, or 277/480Y volts four-wire service.

PRIMARY VOLTAGES

According to location, 2400/4160Y volts, 7200/12,470Y volts, 13,800 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 such customer's electric load is located.

RESTRICTIONS

1. Except for minor loads, with approval of the 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, a 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 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 the 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. 2009-00549 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 (2) 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.

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:

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

(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 customer 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.

Where Company serves a customer with both electric and gas service at the same service location, Company will render a combined bill. Provided, however, a residential customer may request, and Company will render, separate bills under the following conditions: (1) Customer is being threatened with disconnection for non-payment or has already been disconnected for that reason and (2) Customer would be able to pay either the gas or electric portion of his bill and thus retain one service.

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.

TERMS AND CONDITIONS

BILLING

READING OF SEPARATE METERS NOT COMBINED

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

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

TERMS AND CONDITIONS

BILLING

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. T

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.

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 the 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 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).

TERMS AND CONDITIONS

BILLING

RESALE OF ELECTRIC ENERGY T

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 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.

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 KAR5:006, Section 7(1)(b). For combination gas and electric customers, the total deposit will be $230.00. R
3) Company shall 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 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.

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 KAR5:006, Section 7(1)(b). The deposit for a General Service customer T
may be waived when the General Service delivery is to a detached building used in T
conjunction with a Residential Service and the General Service energy usage is no more than T
300 kWh per month. T
2) Company shall 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 percent (10%), 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 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 KAR5:006, 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 percent (10%), 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 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.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

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 the 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 Customer's next budget year.

If Customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove 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 Customer from the provisions of these terms and conditions.

TERMS AND CONDITIONS

Bill Format

LG&E
a PPL company

Customer Service:	1-800-331-7370 (M-F, 7 a.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:	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
04/24/12	$71.03

ACCOUNT INFORMATION

Account Number:	3000-1111-2222
Account Name:	JOHN DOE
Service Address:	1234 Main St LOUISVILLE KY
Next Read Will Occur:	05/08/12 - 05/10/12
Date Bill Mailed:	04/11/12 (Meter Read Portion 07)

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 you account number available when calling to discuss your account.

Averages for Billing Period	This Year	Last Year
Average Temperature	63°	54°
Number of Days Billed	32	29
Electric/kwh per day	24.3	19.60

BILLING SUMMARY

Previous Balance		136.16
Payment(s) Received 3/10 - 4/11		-136.16
Balance as of 4/11		0.00
Current Electric Charges	71.30	
Current Charges as of 4/11		71.30
Total Amount Due		**71.30**

ELECTRIC CHARGES

Rate Type: Residential Electric Service	
Basic Service Charge	8.50
Energy Charge ($0.07242 x 778.00 kwh)	56.34
Electric DSM ($0.00287 x 778 kwh)	2.23
Electric Fuel Adjustment ($0.00472 x 778.00 kwh)	3.67
Environmental Surcharge (0.560% x $70.74)	0.40
Home Energy Assistance Fund Charge	0.16
Total Electric Charges	**$71.30**

Meter Reading Information	
Meter # 70000	
Actual Reading on 4/10/12	13124
Previous Reading on 3/9/12	12346
Current kwh Usage	778
Meter Multiplier	1
Metered kwh Usage	778

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

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	04/24/12	$71.30	$74.87	$	$

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

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

LG&E
PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900062 4#
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40026-9745

Service Address: 1234 Main St

020000000000000000000000124560000001189500000000000000

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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, Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format

T

Account Number 3000-1111-2222 Page 2

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date $3.57

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 1,556 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 LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

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.

TERMS AND CONDITIONS

Bill Format

T

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
04/24/12	$122.18

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:	3000-0216-5900-28
Account Name:	JOHN DOE
Service Address:	1234 ANYWHERE ST
Next Read Will Occur:	05/08/12 - 05/10/12
Date Bill Mailed:	04/11/12 (Meter Read Portion 07)

Averages for Billing Period	This Year	Last Year
Average Temperature	63 °	54 °
Number of Days Billed	32	29
Electric/kwh per day	24.3	19.6
Gas/ccf per day	1.0	2.2

BILLING SUMMARY

Previous Balance		102.30
Payment(s) as of 3/10 - 4/11		(102.30)
Balance as of 4/11		0.00
Electric Charges	71.30	
Gas Charges	50.88	
Utility Charges as of 06/20		122.18
Other Charges		
Total Amount Due		122.18

ELECTRIC CHARGES

Rate Type: Residential Electric Service	
Basic Service Charge	8.50
Energy Charge ($0.07242 x 778.00 kwh)	56.34
Electric DSM ($0.00287 x 778 kwh)	2.23
Electric Fuel Adjustment ($0.00472 x 778.00 kwh)	3.67
Environmental Surcharge (0.560% x $70.74)	0.40
Home Energy Assistance Fund Charge	0.16
Total Electric Charges	$71.30

Meter Reading Information	
Meter # 70000	
Actual Reading on 4/10/12	13124
Previous Reading on 3/9/12	12346
Current kwh Usage	778
Meter Multiplier	1
Metered kwh Usage	778

Please see reverse side for additional charges.

Customer Service 1-800-331-7370 — **PLEASE RETURN THIS PORTION WITH YOUR PAYMENT**

Account Number	Payment Due Date	Amount Due by Due Date	Amount Due 6 Days After Due Date	Winter Help Donation	Amount Enclosed
3000-0216-5900-28	04/24/12	$122.18	$128.29	$	$

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

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

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Rev. 1111 W

PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900082 4#
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40028-8746

Service Address: 1234 Main St

020000000000000000000000124560000001189500000000000000

TERMS AND CONDITIONS

Bill Format

Account Number 3000-0216-5900-28 Page 2

T

GAS CHARGES

Rate Type: Residential Gas Service		Meter Reading Information	
Basic Service Charge	12.50	Meter # 45678	
Gas Distribution Charge ($0.22396 x 35 ccf)	7.84	Actual Reading on 4/10/12	1922
Gas Supply Component ($0.47423 x 35 ccf)	16.60	Previous Reading on 3/9/12	1887
Weather Normalization Adjustment ($0.22396 x 58.850 ccf)	13.18	**Current ccf Usage**	**35**
Gas DSM ($0.01709 x 35.00 ccf)	0.60	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.16	**Metered ccf Usage**	**35**
Total Gas Charges	**$50.88**		

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date **$6.11**

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 1,556 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 LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

Signature: ______________________________

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 the 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 the 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 a 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 the 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 the 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 the 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 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 the 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 the 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 the 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 a 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 the 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

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 Louisville Gas and Electric 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) The 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 25kVA.
2) Where Customer requires poly-phase service or transformer capacity in excess of 25kVA 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 25kVA 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 FOR 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.

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TERMS AND CONDITIONS

Line Extension Plan

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. T T

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 including the service and with the exception of Company's meter.
6) The normal point of delivery shall be at a junction device at the corner of the lot nearest Company's facilities. Customer shall bring Customer's service line to a point within 1 1/2 feet of the junction device with a sufficient length of service conductor left coiled above grade for completion of installation and connection by Company.

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TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS

General (continued)

7) 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. T
8) 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.
9) 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

1) Within the City of Louisville underground district or in those cases where Company's engineering or operating convenience requires the construction of an underground extension to an individual premise, the excess of the cost of an underground extension over that of an overhead extension will be at no cost.
2) In cases other than those specified in 1) above, 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 $6.15 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 $18.66 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.

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TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS (continued)

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. T T T

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 outlines in previous sections of LINE EXTENSION PLAN and the anticipated revenues do not justify the 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.
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 demand billing of the monthly electric 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 Louisville Gas and Electric 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, Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that 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 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 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 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 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: **June 29, 2012**
Date Effective: **February 6, 2009**
Issued By: **Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky**

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Special Contracts

Summary of Proposed Charges Under Electric Special Contracts

Customer 1	Demand Charge:	
	Winter Rate	$12.81 per kW per month
	Summer Rate	$15.22 per kW per month
	Energy Charge	$0.03371 per kWh
Customer 2	Demand Charge:	$10.55 per kW of billing demand per month
	Energy Charge	$0.03280 per kWh

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky

Rates, Terms and Conditions for Furnishing

NATURAL GAS SERVICE

In the seventeen counties of the Louisville, Kentucky, metropolitan area 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 Gas Rate Schedules – Terms and Conditions

GENERAL INDEX
Standard Gas Rate Schedules – Terms and Conditions

Standard Rate **RGS**

Residential Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to residential customers for all domestic purposes in private residences, single occupancy apartments, and common-use areas of multi-purpose occupancy buildings when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served. Such customers also include tenants billed for natural gas consumption or use by other tenants at the same premises that are metered separately.

The term “residential” customers shall include customers using gas in a single-family residential dwelling or unit for space-heating, air conditioning, cooking, water-heating, incineration, refrigeration, laundry drying, lighting, incidental heating, or other domestic purposes, including the use of gas in standby electric generation in domestic applications. If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS. T

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer’s Representative) to the Company in conjunction with the “Notice to Company of Changes in Customer’s Load” set out in the Customer Responsibilities section of the Terms and Conditions of the Company’s Tariff. Additionally, service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers. T

RATE

Basic Service Charge:	$15.50 per delivery point per month	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.23121	I
Gas Supply Cost Component	$ 0.34904	
Total Gas Charge Per 100 Cubic Feet	$ 0.58025	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

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ADJUSTMENT CLAUSES T

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

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	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.

Standard Rate **VFD**

Volunteer Fire Department Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available, 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. If an additional separate point of delivery is requested by a volunteer fire department qualifying for aid under KRS 95A.262 to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS. T

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:	$15.50 per delivery point per month	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.23121	
Gas Supply Cost Component	$ 0.34904	I
Total Gas Charge Per 100 Cubic Feet	$ 0.58025	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

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

Gas Line Tracker	Sheet No. 84	T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Weather Normalization Adjustment	Sheet No. 88	
Franchise Fee and Local Tax	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, Louisville, Kentucky

Standard Rate **CGS**

Firm Commercial Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to customers engaged in commercial activities such as apartment buildings, rooming and boarding dwellings, residential hotels, multi-family row housing, duplexes, other situations where gas is supplied to consumers in two or more dwelling units designed for the primary purposes of residences, and other commercial activities when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination commercial and residential accounts shall be considered commercial if usage for commercial purposes is half or more than half of the total service over the course of a year.

The term "commercial" customers shall include customers using gas in activities related to warehousing, distributing, or selling commodities, providing professional services, wholesale and retail stores, offices, office buildings, hotels, retail bakeries, hospitals, schools, churches, religious or charitable institutions, governmental agencies, other institutions or the like (including local, state, and federal governmental agencies) and for uses other than those involved in manufacturing. Applications related to the use of gas in standby or other electric generation in commercial applications shall not be served under this rate schedule unless (1) T such facilities were installed and operating under this Standard Rate CGS before ninety (90) days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000 T cubic feet per hour and are not for the generation of electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electric supplies during emergency situations.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer's Representative) to the Company in conjunction with the "Notice to Company of Changes in Customer's Load" set out in the Customer Responsibilities section of the Terms and Conditions of the Company's Tariff. Additionally, service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other Customers.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of T 2,000 cubic feet per hour under Rate DGGS shall not be permitted. T

This schedule is also applicable to natural gas service for street lighting to such entities as certificated homeowners associations, businesses, and local, state, and federal governmental agencies.

T

Standard Rate **CGS**
Firm Commercial Gas Service

RATE

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 35.00 per delivery point per month	T T/I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$175.00 per delivery point per month	T T/I

Plus a Charge Per 100 Cubic Feet:

Distribution Cost Component	$ 0.21142	T T/I
Gas Supply Cost Component	0.34904	T
Total Charge Per 100 Cubic Feet	$ 0.56046	T/I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff. T T T T

Off-Peak Pricing Provision:
The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by $0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

ADJUSTMENT CLAUSES

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

Gas Line Tracker	Sheet No. 84	T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Weather Normalization Adjustment	Sheet No. 88	
Franchise Fee and Local Tax	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.

Standard Rate **IGS**
Firm Industrial Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to customers engaged in industrial activities that involve manufacturing or other activities that process, create or change raw or unfinished materials into another form or product when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination industrial and commercial accounts shall be considered industrial if usage for industrial purposes is half or more than half of the total service over the course of a year.

The term “industrial” customers shall include customers involved in activities using gas primarily in a process or processes which either involve the extraction of raw materials from the earth, or a change of raw or unfinished materials into another form or product through the application of heat or heat treating, steam agitation, evaporation, baking, extraction, drying, distilling, asphalt production, and for other similar uses. Applications related to the use of gas in standby or other electric generation in industrial applications shall not be served under this rate schedule unless (1) such facilities were installed and operating under this Standard Rate IGS before ninety (90) days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000 cubic feet per hour and are not for the generation of electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electric supplies during emergency situations. T

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer’s Representative) to the Company in conjunction with the “Notice to Company of Changes in Customer’s Load” set out in the Customer Responsibilities section of the Terms and Conditions of the Company’s Tariff. Additionally, Service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

RATE

Basic Service Charge:		
If all of the customer's meters have a capacity < 5000 cf/hr:	\$ 35.00 per delivery point per month	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	\$175.00 per delivery point per month	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	\$ 0.21523	I
Gas Supply Cost Component	\$ 0.34904	
Total Charge Per 100 Cubic Feet	\$ 0.56427	I
		T

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Standard Rate **IGS**
Firm Industrial Gas Service

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff. T

Off-Peak Pricing Provision:
The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by $0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

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

Gas Line Tracker	Sheet No. 84 T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	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.

Standard Rate **AAGS**
As-Available Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rate schedule is designed to make available to commercial and industrial customers quantities of natural gas that Company may from time to time have available for sale without impairment of service to customers served under other higher priority rate schedules, and which can be supplied from Company's existing distribution system, subject to the special conditions hereinafter set forth.

This rate shall not be available for gas loads which are predominantly space heating in character. In order to ensure that this rate schedule shall not be available for loads which are predominantly space heating in character and which do not consume substantial quantities of gas throughout the year, customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual Delivery Point.

Customers served under Rate G-6 and Rate G-7 as of the first effective date of this Rate AAGS shall have the right to elect service under Rate AAGS, Rate CGS, or Rate IGS. Such Customers that elect to transfer from either Rate G-6 or Rate G-7 to service under Rate AAGS may do so without complying with the requirement set forth above that customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual Delivery Point. Customers not electing service under either Rate CGS or Rate IGS shall receive service hereunder upon the first effective date hereof, irrespective of the November 1 start-date set forth in “Contract-Term” below.

COMPANY NOT OBLIGATED TO CONTINUE SERVICE

Company shall have the right to discontinue the supply of natural gas wholly or in part for such period or periods as, in the sole judgment of Company, may be necessary or advisable to enable it to supply the full gas requirements of its customers served under higher priority rate schedules. Nothing herein shall prevent Company from expanding its obligations under such other rate schedules. Company may decline to accept any additional contracts for service hereunder.

CONTRACT TERM

Customers served under Rate AAGS shall enter a written contract with Company more fully described in the Special Terms and Conditions of this rate schedule. The minimum contract term for service hereunder shall be for a period of at least one (1) year and shall commence on November 1 and be effective through the following October 31, and year to year thereafter, unless terminated by either Company or Customer upon prior written notice on or before the April 30 preceding the October 31 termination date.

Any customer served under Rate CGS or Rate IGS shall provide notice to Company by April 30 of its request for service to be effective commencing on the following November 1.

STANDARD RATE SCHEDULE **AAGS**

As-Available Gas Service

RATE

Basic Service Charge:
$275.00 per delivery point per month

Plus a Charge Per Mcf

Distribution Cost Component	$ 0.6117	I
Gas Supply Cost Component	$ 3.4904	
Total Charge Per Mcf	$ 4.1021	I

The "Gas Supply Cost Component" as shown above is the cost per Mcf determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet Nos. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

ADJUSTMENT CLAUSES

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

Gas Line Tracker	Sheet No. 84	T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

PENALTY FOR FAILURE TO INTERRUPT

Company shall have the right to interrupt sales service under this rate schedule upon eighteen (18) hours' prior notice. Provision of oral notice by telephone to Customer shall be deemed proper notice of interruption of service under this rate schedule.

In addition to the charges set forth above, if the Customer fails to discontinue the consumption of natural gas at its facility at the conclusion of the eighteen- (18-) hour notice period, Company may charge the Customer the following penalty for each Mcf used during the period of interruption in addition to any other remedy available to Company, including, but not limited to, immediate termination of service under this rate schedule, irrespective of the provisions set forth on "Contract Term", and immediate transfer by Company to either Rate CGS or Rate IGS, as applicable.

Customer shall be charged a per Mcf penalty charge equal to $15.00 plus the mid-point price posted in "*Platts Gas Daily*" for Dominion--South Point on the day to which such interruption of service is applicable, plus any other charges under this rate schedule for such unauthorized usage by Customer that occurs following the conclusion of the eighteen- (18-) hour notice of interruption by Company to Customer. T

If Customer is delivering quantities of gas to Company pursuant to Rider TS during such period of interruption, the charge described in the immediately preceding paragraph shall be applicable only to those quantities used by customer in excess of those being delivered by Customer to Company. T

Company shall not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of this rate schedule. Payment of penalty charges hereunder shall not be considered an exclusive remedy for failure to comply with the notice of interruption, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

SPECIAL TERMS AND CONDITIONS

1. Service shall be supplied hereunder only at such times and in such volumes as Company, in its sole judgment, determines that gas is available for such service without impairment of service supplied under other rate schedules.

2. Each customer served hereunder shall be required to enter into a written contract specifying, among other things, realistic monthly requirements for gas under this rate schedule. Such volumes shall be used as the basis for apportionment of gas when the total customer requirements exceed the quantity of gas available for service hereunder.

3. The customer shall contract under this rate schedule for a specified quantity of gas stated in terms of maximum required deliveries in Mcf per day. On no day shall Company be obligated to supply gas in excess of such contract quantity. In no case will Company be obligated to supply gas to Customer at greater volumes and greater rates of flow than those historically delivered by Company to Customer.

4. Customer shall discontinue taking service upon applicable notice by Company to do so.

5. No gas service whatsoever to Customer’s equipment or process served hereunder shall be supplied or permitted to be taken under any other of Company's gas rate schedules during periods of interruption.

6. Upon commencement of service hereunder, Customer shall be required to certify that Customer’s alternate fuel facilities are operational and alternate fuel is on site and capable of use. Company may, at its discretion, verify such certification through physical inspection of Customer’s facility. In the event that Customer does not have alternate fuel facilities, Customer shall certify that the processes which utilize gas delivered hereunder are capable of complete discontinuance of natural gas use. Company may request Customer to verify either of the foregoing alternatives on an annual basis on or before October 1 of each year. Failure of Customer to annually certify either of the above alternatives shall result, in the sole discretion of Company, in immediate termination of service under this rate schedule and the immediate transfer to the appropriate firm sales rate schedule, either Rate CGS or Rate IGS.

7. Service hereunder must be supplied through a separate meter and physically isolated from any other service provided by Company under other rate schedules.

8. Company shall not be obligated to install or construct any facilities (other than necessary meters and regulators) in order to provide service hereunder.

9. Any Customer contracting for service hereunder, other than a Customer transferring from either Rate G-6 or Rate G-7 as stipulated above, may be required, in the sole discretion of Company, either prior to electing service hereunder or at anytime thereafter, to have appropriate remote metering devices. The remote metering devices allow Company to monitor the Customer's usage and determine compliance with notice of interruption of service hereunder. The Customer shall be responsible for the cost of the remote metering equipment and the cost of its installation.

   Any Customer required to have remote metering as described above shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

   Any Customer required to have remote metering shall be responsible for providing the necessary and adequate electric and telephone service to provide this metering within thirty (30) days of Company's notice to Customer that such remote metering shall be required. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide such remote metering.

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.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof.

Standard Rate **FT**

Firm Transportation Service (Transportation Only) T

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to existing commercial and industrial customers who consume at least 50 Mcf each day at each individual Delivery Point during each month of the twenty-four (24) months prior to the March 31 service request date, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's Pipeline Transporter, and have requested Company to utilize its system to transport, by displacement, such customer-owned gas to Customer's place of utilization. Customers electing to transfer from another service shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rate schedule shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30. T T T T

For new customers whose historical gas consumption is not available, Company will determine Customer's eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Any such transportation service hereunder shall be conditioned on Company being granted a reduction in billing demands by its Pipeline Transporter corresponding to the Customer's applicable transportation quantities.

Transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Service under this rate schedule shall not be available to customers with a Maximum Daily Quantity ("MDQ") in excess of 20,000 Mcf/day. In the event that Customer's MDQ exceeds 20,000 Mcf/day, Company may terminate service under this rate schedule upon thirty (30) days prior written notice. Additionally, customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer's MDQ, are not eligible for service under this rate schedule. T

CHARACTER OF SERVICE

Transportation service under this rate schedule shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter ("Receipt Point") to the Delivery Point at the Customer's place of utilization ("Delivery Point"), subject to paragraph 6 of the Special Terms and Conditions. T

T

Standard Rate **FT**

Firm Transportation Service (Transportation Only) T

Due to the physical configuration of Company's system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company's sole obligation hereunder is to redeliver Customer's gas from the Receipt Point to the Delivery Point. Accordingly, Company has no obligation to deliver to the Customer a volume of gas, either daily or monthly, which differs from the volume delivered to Company at the Receipt Point.

Company will provide service to meet imbalances only on an as-available basis. For purposes used herein, "Imbalances" are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point. When Company can provide such service, the Utilization Charge for Daily Imbalances shall apply to daily imbalances in excess of ±5% of the delivered volume of gas as set forth herein. Company shall issue an Operational Flow Order as set forth herein during periods when service cannot be provided to meet daily imbalances.

Customers served under this rate may elect to become a member of an FT Pool pursuant to Rider PS-FT.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, and any other charges set forth herein, the following charges shall apply.

Administrative Charge: $600.00 per Delivery Point per month T/I

Distribution Charge Per Mcf: $0.43 T

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rate FT. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rate FT in order to recover from (or refund to) transferring sales customers any under- or over-collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly Gas Supply Clause filings.

For customers electing service under Rate FT effective November 1, 2010,
the Gas Cost True-Up Charge shall be:

($0.1593) per Mcf for Bills Rendered On and After May 1, 2012

For customers electing service under Rate FT effective November 1, 2011,
the Gas Cost True-Up Charge shall be:

($0.1709) per Mcf for Bills Rendered On and After May 1, 2012

Standard Rate **FT**

Firm Transportation Service (Transportation Only) T

Minimum Daily Threshold Requirement and Charge: When Customer's daily usage falls below the Minimum Daily Threshold Requirement, Customer will be charged a Minimum Daily Threshold Charge equal to the difference between the Minimum Daily Threshold Requirement and the Customer's actual consumption in Mcf for that day multiplied by the Distribution Charge hereunder. The Minimum Daily Threshold Requirement is equal to the minimum daily volume of 50 Mcf. Such Minimum Daily Threshold Charge shall be accumulated for each day of the applicable month and billed during that month in accordance with the following formula: T

Minimum Daily Threshold Charge =

(Minimum Daily Threshold minus Customer Usage on Given Day) times the Distribution Charge

Such daily amount shall be accumulated for each day of the month and the total will be applied to Customer's bill.

Payment of the Minimum Daily Threshold Charge is not a remedy for Customer's failure to meet the Minimum Daily Threshold Requirement for service under Rate FT. In the event that Customer does not meet the Minimum Daily Threshold Requirement for one-hundred twenty (120) days during a given Contract Year, service to Customer under Rate FT may be discontinued by Company. Customer will receive thirty (30) days prior written notice that Customer will be removed from Rate FT and returned to firm sales service under either Rate CGS or IGS as applicable.

Other: In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then Customer shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

ADJUSTMENT CLAUSES

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	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.

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.

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Standard Rate **FT**

Firm Transportation Service (Transportation Only) T

IMBALANCES

Company will calculate on a daily and monthly basis the Customer's imbalance resulting from the difference between the metered usage of the Customer and the volumes that the Customer has delivered into Company's system. This will be calculated as follows: T

Imbalance = Metered Usage - Delivered Volume

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volume}}$$

The term "day" or "daily" shall mean the period of twenty-four (24) consecutive hours beginning at 10:00 a.m., Eastern Clock Time.

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from Customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lowest daily mid-point price posted in "*Platts Gas Daily*" for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

When Total Net Negative Imbalance Percentage is:	The following percentage shall be multiplied by the above-referenced "*Platts Gas Daily*" price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall be billed for the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the highest daily mid-point price posted in "*Platts Gas Daily*" for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

Standard Rate **FT**

Firm Transportation Service (Transportation Only) T

T

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-referenced "*Platts Gas Daily*" price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	110%
>10% to ≤15%	120%
>15% to ≤20%	130%
>20%	140%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a Customer with a monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the Customer's monthly bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

UTILIZATION CHARGE FOR DAILY IMBALANCES

Should an imbalance exceed ±5% of the delivered volume of gas on any day when an Operational Flow Order (as described below) has not been issued, then Company shall charge the Utilization Charge for Daily Imbalances times the recorded imbalance greater than ±5% of the delivered volume of gas for each daily occurrence. The Utilization Charge for Daily Imbalances is the sum of the following:

Daily Demand Charge:	$0.1722 per Mcf
Daily Storage Charge:	$0.1833
Utilization Charge for Daily Imbalances:	$0.3555 per Mcf

Note: The Daily Demand Charge may change with each filing of the GSCC.

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These charges are in addition to any other charges set forth herein. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed ±5% of the delivered volume. Company shall not have an obligation to provide balancing service for any volumes of gas hereunder. T

OPERATIONAL FLOW ORDERS

Company shall have the right to issue an Operational Flow Order ("OFO") which will require actions by Customer to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. Customer shall be responsible for complying with the directives contained in the OFO.

Notice of an OFO shall be provided to Customer at least twenty-four (24) hours prior to the beginning of the gas day for which the OFO is in effect. Customer shall respond to an OFO by adjusting its deliveries to Company's system as directed in the OFO within the specified timeframe. If Customer is a member of an FT Pool, it is the responsibility of the FT Pool Manager, not Company, to convey OFOs to Customers in its FT Pool.

Upon issuance of an OFO, Company will direct Customer to comply with one of the following conditions: (a) Customer must take delivery of an amount of natural gas from Company that is no more than the daily amount being delivered by the Pipeline Transporter to Company for Customer; or (b) Customer must take delivery of an amount of natural gas from Company that is no less than the daily amount being delivered by the Pipeline Transporter to Company for Customer. Customer shall respond to an OFO by either adjusting its deliveries to Company's system or its consumption at its facility. All volumes taken by Customer in excess of volumes delivered by Pipeline Transporter to Company for Customer in violation of the above "condition (a)" OFO shall constitute an unauthorized receipt by Customer from Company. All volumes taken by Customer less than volumes delivered by Pipeline Transporter to Company for Customer in violation of "condition (b)" OFO shall constitute an unauthorized delivery by Customer to Company. Customer shall be subject to the OFO Charge on the day for which the OFO was violated, plus the applicable UCDI charges and any other charges under this rate schedule for such unauthorized receipts or deliveries that occur

Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT.

The OFO Charge shall be equal to $15.00 plus the mid-point price posted in "*Platts Gas Daily"* for Dominion South Point per Mcf on the day for which the OFO was violated, plus any other charges under this rate schedule.

Company will not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of an OFO. Payment of OFO Charges hereunder shall not be considered an exclusive remedy for failure to comply with the OFO, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

OPTIONAL SALES AND PURCHASE TRANSACTION T

Customer may agree to sell its natural gas supplies to Company, and Company may agree to purchase natural gas supplies from Customer pursuant to Company's Curtailment Rules. If Company purchases natural gas from Customer, such gas will not be redelivered to Customer, and Customer shall discontinue or otherwise interrupt the usage of such natural gas.

RETURN TO FIRM SALES SERVICE

Return to firm sales service is contingent upon the ability of Company to secure the appropriate quantities of gas supply and transportation capacity with Company's Pipeline Transporter, as determined solely by Company.

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rate schedule. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

The Customer shall be responsible for the cost of this remote metering equipment and the cost of its installation.

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide remote metering by October 1 of the year that the Customer's Rate FT service becomes effective. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be transported by Company for Customer, Delivery Points, timing of receipts and deliveries of gas by Company, and any other matters relating to individual Customer circumstances.

2. As further described below, Customer shall specify to Company the daily volume of gas required by Customer. Such volume shall be stated in Mcf/day and converted to MMBtu/day using a standard conversion factor as may be specified by Company from time to time. At least ten (10) days prior to the beginning of each month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's

Standard Rate **FT**

Firm Transportation Service (Transportation Only) T

SPECIAL TERMS AND CONDITIONS (continued) T

system for Customer's account. Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by Customer to Company no later than 8:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from Customer daily nominations, or changes thereto, that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company. Company will not be obligated to utilize its underground storage capacity for purposes of this service.

3. In no case will Company be obligated to deliver gas, including both gas transported and gas sold, to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be referred to as the Maximum Daily Quantity ("MDQ"). The MDQ is the maximum daily volume of gas, as determined by Company, based on Customer's historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine the MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis.

4. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.

5. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

6. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

7. Should Customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will not be obligated hereunder to provide standby quantities for purposes of supplying such Customer requirements.

8. Company shall not be required to render service under this rate schedule to any Customer that fails to comply with any and all of the terms and conditions of this rate schedule.

TERMS AND CONDITIONS

Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

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, Louisville, Kentucky**

Louisville Gas and Electric Company

Standard Rate **DGGS**
Distributed Generation Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to customer-owned electric generation facilities except (i) when such natural gas is limited to the production of electricity for Customer's own use during emergency situations during which Customer's normal supply of electricity is not otherwise available, and (ii) when such electric generation facilities have a total connected load of less than 2,000 cubic feet per hour. Natural gas purchased for electric generation facilities with a total connected load of 2,000 or more cubic feet per hour, or purchased to generate electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electrical supplies during emergency situations shall be subject to this tariff. Additionally, service under this Standard Rate DGGS shall be applicable only to electric generation facilities described above and installed and operating on and after ninety (90) days after August 1, 2010, (and therefore not eligible for service under Standard Rates CGS or IGS) by commercial and industrial customers. T

Service hereunder shall be at a single delivery (custody transfer) point and where distribution mains are adjacent to the premises to be served. Gas sales service provided hereunder shall be metered and billed separately from gas service provided under any other rate schedule.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of T
2,000 cubic feet per hour under Rate DGGS shall not be permitted. T

Sales service hereunder shall be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other customers. Company may decline to accept customers under this rate schedule with a connected load of more than 8,000 cubic feet per hour. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this rate schedule.

If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, such residential customer shall be served under Rate DGGS.

CHARACTER OF SERVICE
Gas sales service under this rate schedule shall be considered firm.

RATE
In addition to any other charges set forth herein, the following charges shall apply.

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 35.00 per delivery point per month	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$175.00 per delivery point per month	I

Demand Charge per 100 cubic feet of Monthly Billing Demand: $1.0900 I

Plus a Charge Per 100 Cubic Feet:

Distribution Cost Component	$0.03222	I
Gas Supply Cost Component	0.34904	
Total Charge Per 100 Cubic Feet	$0.38126	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

The total monthly minimum bill shall be the sum of the minimum monthly Demand Charge and the Monthly Basic Service Charge.

In no case shall Company be obligated to deliver greater volumes hereunder than those specified in the written contract between Customer and Company. Payment of any and all charges hereunder shall not be considered an exclusive remedy for takes in excess of the maximum daily quantity (“MDQ”), nor shall the payment of such charges be considered a substitute for any other remedy (including, but not limited to, physical discontinuance or suspension of service hereunder) available to Company.

ADJUSTMENT CLAUSES

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

Gas Line Tracker	Sheet No. 84	T
Franchise Fee and Local Tax	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.

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.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be sold by Company to Customer, and any other matters relating to individual customer circumstances.

2. The minimum contract term for service hereunder shall be for a period not less than five (5) years commencing from the effective date thereof.

3. Such written contract shall specify the minimum delivery pressure, the maximum hourly rate (“MHR”), and the maximum daily quantity (“MDQ”). The MHR is the maximum hourly gas load in 100 cubic feet that the Customer’s installation will require when operating at full capacity. The MDQ shall be twenty-four (24) times the MHR. The MDQ is the Monthly Billing Demand and shall not be less than 480 (four hundred and eighty) Ccf. T

4. In no case shall Company be obligated to make deliveries hereunder at a pressure greater than thirty (30) psig, or the prevailing line pressure, whichever is less.

5. Increases in the MDQ may be requested annually by Customer. Customer may request Company to increase the MDQ at least ninety (90) days in advance of the anniversary date of the written contract. Such increases in the MDQ that are acceptable to Company in its sole discretion shall be effective on the anniversary date of the effective date of the written contract.

6. In the event that Company agrees to install any Company-owned facilities required to serve Customer, such facilities to be installed by Company shall be specified in the written contract and the cost of such facilities and installation thereof shall be paid by Customer to Company.

TERMS AND CONDITIONS

Service under this rate is subject to Company’s Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

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 (2) percent fast, the Customer will be charged $90.00 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 gas service R
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. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. No charge R
will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection.

Customers under Gas Rates RGS, CGS and IGS may request and be granted temporary suspension of gas service. In the event of such temporary suspension, Company will make a charge of $28.00 to cover disconnection and reconnection of gas service, such charge to be R
made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. R

INSPECTION CHARGE

With respect to Customer's service line and house line inspections prior to initiation or resumption of gas service, Company will make two such inspections without charge. When more than two trips are necessary to complete the inspections at any one location, a charge of $150.00 will be made for each additional trip. I

CHARGE FOR TEMPORARY AND SHORT TERM SERVICE

The customer shall pay the cost of all material, labor and expense incurred by Company in supplying gas service for any temporary or short term use, in addition to the regular rates for service without pro-rating of rate blocks or minimum charges for service of less than thirty days in a regular meter reading period.

ADDITIONAL TRIP CHARGE T

Under Rate FT, Rider TS-2, and Rider GMPS, if the Company is required to make additional visits to the meter site due to the Company's inability to gain access to the meter location, or the necessary Communication Link (such as electric and telephone service) has not been properly installed by Customer, or the Customer's Communication Link is not working properly, the Company may charge the Customer for any additional trip to the site at a per-visit rate of $150.00.

Standard Rate Rider **TS**

Gas Transportation Service/Standby

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to commercial and industrial customers served under Rate CGS and Rate IGS who consume either (a) an average of at least 50 Mcf each day during the billing cycle at each individual Delivery Point, or (b) 50,000 Mcf annually at each individual Delivery Point. Also available to customers served under Rate AAGS who consume at least 50 Mcf each day during the billing cycle at each individual Delivery Point. Customer shall have purchased natural gas elsewhere, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. Any transportation service hereunder will be conditioned on Company being able to retain or secure adequate standby quantities of natural gas. In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Rider TS shall continue to be effective for customers who have previously elected to transport T
under Rider TS as of the effective date hereof. However, service hereunder shall terminate on T
October 31, 2013, at which point Rider TS shall no longer be in effect. T

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $592.00 per Delivery Point per month I

	CGS	IGS	AAGS	
Distribution Charge Per Mcf	$2.1142	$2.1523	$0.6117	I
Pipeline Supplier’s Demand Component	0.8800	0.8800	0.8800	
Total	$2.9942	$3.0323	$1.4917	I

The **"Distribution Charge"** applicable to Rate CGS and IGS monthly quantities in excess of 100 Mcf shall be reduced by $0.50 per Mcf during the seven off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component: Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's Gas Supply Clause.

ADJUSTMENT CLAUSES

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

IMBALANCES

Company will calculate on a monthly basis the Customer's imbalance resulting from the difference between the metered usage of the Customer and the volumes that the Customer has delivered into Company's system. This will be calculated as follows:

Imbalance = Metered Usage - Delivered Volumes

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volumes}}$$

CASH-OUT PROVISION FOR POSITIVE MONTHLY IMBALANCES (STANDBY SERVICE)

Company will provide standby quantities of natural gas hereunder for purposes of supplying Customer's requirements should Customer be unable to obtain sufficient transportation volumes. Such standby service will be provided at the same rates and under the same terms and conditions as those set forth in Company's applicable rate schedule under which it sells gas to Customer.

CASH-OUT PROVISION FOR NEGATIVE MONTHLY IMBALANCES

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lowest daily mid-point price posted in "*Platts Gas Daily"* for Dominion South Point during the month in which the negative T
imbalance occurred. The appropriate percentage shall be dependent on the Customer's monthly negative imbalance percentage to be applied as follows:

When Total Net Negative Balance Percentage is:	The following percentage shall be multiplied by the above referenced "*Platts Gas Daily"* price for Dominion South Point: T
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for negative imbalances that fall within each category. For example, a Customer with a negative monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of T
the imbalance and at the 5% to 10% price for 4% of the imbalance. T

T

All such adjustments shall be shown and included on the Customer's bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

Variations in MMBtu Content:
Changes in billings of the "cash-out" provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

SPECIAL TERMS AND CONDITIONS

1. Service under this rider shall be performed under a written contract between Customer and Company setting forth specific arrangements as to volumes to be transported by Company for Customer, points of delivery, methods of metering, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

2. At least ten days prior to the beginning of each month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for Customer's account. Customer shall give Company at least twenty-four (24) hours' prior notice of any subsequent changes to scheduled deliveries.

3. In no case will Company be obligated to supply gas to Customer, including both gas sold to Customer and gas transported hereunder, at greater volumes and greater rates of flow than those historically purchased by Customer from Company.

4. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.

5. All volumes of natural gas transported hereunder shall be of the same quality and meet the same specifications as that delivered to Company by its pipeline transporter.

6. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

7. Should Customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will provide standby quantities of natural gas to Customer as set forth in Customer's standard rate schedule CGS, IGS, or AAGS. In the event of an interruption of sales service to a Customer served under Rate AAGS, as provided for in that rate schedule, Company shall continue to deliver quantities of customer-owned natural gas in amounts equal to such quantities being delivered by pipeline transporter for Customer. During such periods of interruption, a Customer served under Rate AAGS shall not take quantities of natural gas in excess of those being delivered to Company on Customer's behalf. If Customer takes natural gas in excess of such quantities, Customer shall be subject to penalties in accordance with Company's Curtailment Rules.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

Standard Rate Rider **TS-2** N

Gas Transportation Service/Firm Balancing Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to existing commercial and industrial customers served under Rates AAGS, CGS, and IGS who consume at least 25,000 Mcf annually at each individual Delivery Point during the two (2) years ending with the March 31 service request date.

This rider is available for qualified customers electing to transport under Rider TS-2 beginning November 1, 2013.

Customers electing service under this rider shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rider shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30.

For new customers whose historical gas consumption is not available, Company will determine Customer's eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Customer shall have purchased natural gas elsewhere, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization

In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Service under this rider shall not be available to Customers with a Maximum Daily Quantity ("MDQ") in excess of 5,000 Mcf/day. In the event that Customer's MDQ exceeds 5,000 Mcf/day, Company may terminate service under this rider upon thirty (30) days prior written notice. Additionally, Customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer's MDQ, are not eligible for service under this rider.

CHARACTER OF SERVICE

Transportation service under this rider shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter ("Receipt Point") to the Delivery Point at the Customer's place of utilization ("Delivery Point"), subject to paragraph 6 of the Special Terms and Conditions.

Due to the physical configuration of Company's system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company will provide service to meet imbalances on a firm basis. For purposes used herein, "Imbalances" are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point.

Customers served under this rider must designate a TS-2 Pool Manager and become a member of a TS-2 Pool pursuant to Rider PS-TS-2.

Company shall issue an Action Alert as set forth in Rider PS-TS-2 when, in Company's sole discretion, such Action Alert is required to manage loads served under Rider TS-2. It is the responsibility of the TS-2 Pool Manager, not Company, to convey Action Alerts to Customers in the TS-2 Pool.

Any imbalances (over- or under-deliveries) incurred by TS-2 Pool Manager on behalf of Customer shall be resolved through the application of the cash-out mechanism incorporated in Rider PS-TS-2.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $600.00 per Delivery Point per month

	CGS	IGS	AAGS
Distribution Charge Per Mcf	$2.1142	$2.1523	$0.6117
Pipeline Supplier's Demand Component	0.8800	0.8800	0.8800
Total	$2.9942	$3.0323	$0.4917

The **"Distribution Charge"** applicable to Rate CGS and IGS monthly quantities in excess of 100 Mcf shall be reduced by $0.50 per Mcf during the seven off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component: Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's Gas Supply Clause.

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder and not previously served under Rider TS. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rider TS-2. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rider TS-2 in order to recover from (or refund to) transferring sales customers any under- or over-collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly Gas Supply Clause filings.

For customers electing service under Rider TS-2 effective November 1, 2010, the Gas Cost True-Up Charge shall be:

($0.1593) per Mcf for Bills Rendered On and After May 1, 2012

For customers electing service under Rider TS-2 effective November 1, 2011, the Gas Cost True-Up Charge shall be:

($0.1709) per Mcf for Bills Rendered On and After May 1, 2012

Minimum Annual Threshold Requirement and Charge: When Customer's annual usage falls below the Minimum Annual Threshold Requirement, Customer will be charged a Minimum Annual Threshold Charge equal to the difference between the Minimum Annual Threshold Requirement of 25,000 Mcf and the Customer's actual consumption in Mcf during each Contract Year which difference shall be multiplied by the peak period Distribution Charge of the applicable sales rate schedule. Such Minimum Annual Threshold Charge shall be billed during the month following the close of the Contract Year in accordance with the following formula

Minimum Annual Threshold Charge =

(Minimum Annual Threshold minus Customer's Annual Usage) times the Peak Period Distribution Charge

Such amount shall be applied to Customer's November bill.

Payment of the Minimum Annual Threshold Charge is not a remedy for Customer's failure to meet the Minimum Annual Threshold Requirement for service under Rider TS-2. In the event that Customer does not meet the Minimum Annual Threshold Requirement for two (2) consecutive years (as determined for the 12 months ended October), service to Customer under this rider may be discontinued. Customer and its TS-2 Pool Manager will receive notice by December 1 that Customer will be removed from the TS-2 Pool and returned to firm sales service effective April 1 of the following year.

New customers qualifying for service hereunder and who begin service prior to the November 1 date specified above shall not be subject to any Minimum Annual Threshold Charge for service prior to the November 1 date immediately following the commencement of service hereunder.

Monthly Telemetry Charge: $300.00 per Delivery Point per month

ADJUSTMENT CLAUSES

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rider. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide remote metering by October 1 of the year that Customer's service under Rider TS-2 becomes effective. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

SPECIAL TERMS AND CONDITIONS

1. Service under this rider shall be performed under a written contract between Customer and Company setting forth specific arrangements as to volumes to be transported by Company for Customer, TS-2 Pool Manager designated by Customer, points of delivery, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

   Customer may appoint only one TS-2 Pool Manager for a given period. If Customer elects to change its TS-2 Pool Manager, Customer shall notify Company and execute and return the required documentation of its election to change its TS-2 Pool Manager at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective. Except as provided for in rider TS-2, no customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year. In appointing a TS-2 Pool Manager, Customer acknowledges that it has appointed the designated TS-2 Pool Manager to act as its limited agent in the performance of certain stated functions and to assume certain stated responsibilities with

SPECIAL TERMS AND CONDITIONS (continued)

regard to transportation under Rider TS-2, including the requesting and receiving of information, the scheduling of gas flows, and all related duties. Customer will continue to be responsible for any and all costs, fees, and other liabilities as the result of the actions or inactions of TS-2 Pool Manager as its limited agent. Customer shall indemnify, defend, and hold Company harmless from any costs (including, but not limited to, reasonable attorney fees), expenses, losses, or liabilities, incurred (a) as a result of Company's performance when relying upon the authority of the TS-2 Pool Manager, (b) as a result of Company's reliance upon Customer's representation that it has express authority to appoint said TS-2 Pool Manager as its limited agent, and (c) due to the Customer's or TS-2 Pool Manager's failure to strictly comply with the provisions of Rider TS-2 or Rider PS-TS-2.

2. In no case will Company be obligated to deliver gas to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be referred to as the Maximum Daily Quantity ("MDQ"). The MDQ is the maximum daily volume of gas, as determined by Company, based on Customer's historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine Customer's MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis.

3. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.

4. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

5. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

6. In the event of an interruption of service to a Customer served under Rate AAGS, as provided for in that rate schedule, Customer shall discontinue the use of natural gas as specified therein, be subject to the penalties set forth therein, and discontinue deliveries of natural has hereunder..

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to all commercial and industrial customers that request the Company to install a gas meter pulse generator which is a meter-related service not otherwise provided by the Company. This service is only available for customer metering sites using positive displacement meters, orifice meters, or ultrasonic metering technology, so long as the meter capacity is 3,000 cubic feet per hour or greater..

CHARACTER OF SERVICE

The service provided hereunder is a pulse generator (dry electrical contact closure) suitable for generating electrical pulses.

For customers not served under Rate Schedule FT or Rider TS-2, a separate pulse generator will be provided for each gas meter installed at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors may need to be applied by the Customer. T

For customers served under Rate Schedule FT or Rider TS-2, a separate pulse generator will be totalized for gas meters at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors are applied to the volumes provided and need not be applied by the Customer. T

The Customer shall be responsible for providing and maintaining the necessary and adequate electric and telephone service ("Communication Links") per the Company's specifications.

The Company will provide the pulse generator(s). Customer Installed Equipment is any equipment or wiring installed by the Customer, or someone other than Company acting on behalf of Customer, and could include, but would not be limited to, any device such as a data concentrator, totalizer, programmable logic controller, remote terminal unit, or similar equipment used for the purpose of collecting the pulse data. Customer is responsible for installation of wiring to the pulse generator(s) and is responsible for providing the wetting voltage necessary to generate electrical pulses, as well as all dielectric isolation fittings, surge protection and electrical barriers. The wetting voltage must be a regulated DC voltage of 30 volts or less and 10 mA or less, or as otherwise determined by the Company. If Customer Installed Equipment is located within fifteen (15) feet of any gas pipeline flanges, gas regulators, or gas pressure relief devices; or if gas meters are installed in an enclosed space, then Customer Installed Equipment must be installed in accordance with National Electrical Code Class 1 Division 2 requirements.

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

A failure of the pulse generator will not be detected by Company on any routine meter reading nor necessarily during other operations. Therefore, Customer is required to recognize and report any problems with the pulse generator.

RATE

In addition to any other charges set forth herein, the following charges shall apply.

For Customers Served Under Rate Schedule FT or Rider TS-2: T
Monthly Charge: $ 7.25 R

For Customers Not Served Under Rate Schedule FT or Rider TS-2: T
Monthly Charge: $24.60 I

If replacement of the Gas Meter(s) is necessary for the installation of a pulse generator, then Customer shall be responsible for the actual meter and meter installation cost of such Gas Meter(s). Customer shall be responsible for making at its cost any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in the event a replacement Gas Meter is necessary or as otherwise required by Company to facilitate this service.

SPECIAL TERMS AND CONDITIONS T

1. All Customer Installed Equipment shall be owned, maintained and operated by Customer at its sole cost, including the installation thereof. Dielectric isolation fittings, surge protection and electrical barriers will be used by Customer at Customer's cost when connecting to Company's meter facilities. There may be instances where Company determines, in its sole discretion, that dielectric isolation fittings are not necessary. If such fittings are not determined to be necessary, Company shall notify the Customer in writing. All connections of Customer Installed Equipment to Company facilities and equipment will be made by Company or witnessed by Company's representatives. If applicable, all of Customer's Installed Equipment must be installed within fifty feet of Company's metering telemetry equipment. The Company has the right to inspect Customer's installed equipment, prior to initiating the pulse out service, but has no obligation to do so, and in conducting any inspection the Company is not undertaking or accepting any obligation, responsibility or duty whatsoever with regard to Customer Installed Equipment.

2. Customer agrees and understands that pulse data generated by service under this tariff shall not be used for purposes of billing by Company for natural gas volumes used by the Customer. Furthermore, Customer agrees and understands the pulse generator(s) supplied do not represent a rate of flow, but only a total volume, and should not be used for process control or other purposes. T

3. Customer warrants that Customer will not use pulse data in a manner that could result in or create an unsafe condition of any kind or type should the data signal from Company's natural gas metering equipment be lost or inaccurate for any reason whatsoever. Customer further warrants that any installation, operation, maintenance, repair, replacement or removal of Customer Installed Equipment shall not interfere with Company's access to or operation and maintenance of its facilities or equipment. T

4. Company shall not be required to restore any lost data signal. Company reserves the right to upgrade, change, alter or remove any portion or all of Company's facilities, discontinue the data signal or require removal or disconnection of Customer's Installed Equipment, for any reason and without liability to Customer, with prior written notice to Customer. Customer may report data loss or interruptions during normal working hours to the Company. If Customer fails to comply within the time set forth in Company's written request, Company shall have the right to immediately remove Customer Installed Equipment without liability to Customer, and Customer shall reimburse Company for the actual cost of removing said Equipment. All costs associated with responding to Customer's calls and problems relating to service hereunder (including but not limited to call-out, overtime and call-back) shall be paid by Customer upon receipt of Company's invoice.

5. Company makes no representation and provides no warranty or guarantee relating to the operation of, or accuracy or availability of, the data signal provided through Company's equipment. Data received is for informational purposes only, and Company shall not be liable for Customer's use of Company's equipment or data taken therefrom for any purpose.

6. Either party may terminate service under this Rate Schedule upon sixty (60) days prior written notice. Customer shall immediately disconnect and remove Customer's Installed Equipment upon termination, or shall request Company to do so at Customer's sole cost. T

7. Customer shall indemnify, defend and hold Company, its parents, affiliates and subsidiaries and their officers, directors, and employees harmless, to the extent allowed by law, from and against any and all claims, suits, causes of action, liabilities, losses, damages, penalties, fines, fees, assessments, costs and expenses (including attorney's fees and costs incurred in any action or proceeding between Company and Customer or Company and a third party) whatsoever for damages to property or injuries or death to persons (including but not limited to Company's and/or Customer's employees or contractors), arising directly or indirectly from the installation, operation, maintenance, repair, removal, or use of Customer Installed Equipment or involving any inaccurate pulse data or the reliance of Customer or any third party on any pulse data provided pursuant to service hereunder. T

TERMS AND CONDITIONS T

Service under this rate is subject to Company's Terms and Conditions governing the supply of T
gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not T
in conflict with nor inconsistent with the specific provisions hereof. T

Standard Rate Rider **PS-TS-2** N

Pooling Service – Rider-TS-2

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to TS-2 Pool Managers.

Service under this rider shall not be available for new pool managers until the November 1 following the effective date of this rider.

For the purpose of this rider, a “TS-2 Pool Manager” is defined as an entity which has been appointed by a customer or group of customers served under Rider TS-2 to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties. A single Rider TS-2 customer may appoint itself as its own Pool Manager.

RATE

In addition to any charges billed directly to TS-2 Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rider TS-2, the following charge shall apply to the TS-2 Pool Manager:

PS-TS-2 Pool Administrative Charge: $75 per Customer in TS-2 Pool per month

Other: In the event that TS-2 Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then TS-2 Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

ADJUSTMENT CLAUSES

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

CHARACTER OF SERVICE

Service under this rider allows a TS-2 Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more transportation customers that comprise a PS-TS-2 Pool.

The TS-2 Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of the Customers in the TS-2 Pool.

The TS-2 Pool Manager must secure its own upstream capacity from Pipeline Transporter to meet the requirements of the Customers in the TS-2 Pool, up to the total Maximum Daily Quantity of the Customers who are in the TS-2 Pool.

ACTION ALERTS

Company shall have the right to issue an Action Alert (“AA”) which will require actions by the TS-2 Pool Manager to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. It is the responsibility of the Pool Manager, not Company, to convey an AA to Customers in its TS-2 Pool. Pool Manager shall be responsible for complying with the directives contained in the AA.

Notice of an AA shall be provided to TS-2 Pool Manager at least eighteen (18) hours prior to the beginning of the gas day for which the AA is in effect. TS-2 Pool Manager shall respond to an AA by adjusting its deliveries to Company's system as directed in the AA within the specified timeframe.

Upon issuance of an AA, Company will direct TS-2 Pool Manager to deliver to Company from 0% to 100% of the total MDQ of those Customers in the TS-2 Pool (the PMDQ as defined hereafter). Any volume delivered by TS-2 Pool Manager that differs (either more or less) from the volume specified in the AA shall be subject to an Action Alert Charge.

Company may, in its sole discretion, issue an AA to an individual Pool Manager taking service under Rider PS-TS-2 without issuing an AA to all Pool Managers taking service under Rider PS-TS-2.

The Action Alert Charge shall be equal to $5.00 plus the mid-point price posted in *Platts Gas Daily* for Dominion South Point per Mcf on the day for which the AA was violated, plus any other charges under this rider.

Company will not be required to provide service under this rider for any TS-2 Pool Manager that does not comply with the terms or conditions of an AA. Payment of Action Alert Charges hereunder shall not be considered an exclusive remedy for failure to comply with an AA, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

IMBALANCES

Company will calculate on a daily and monthly basis the TS-2 Pool Manager’s imbalance resulting from the difference between the metered usage of the Customers in the TS-2 Pool and the volumes that the TS-2 Pool Manager has delivered into Company's system for the Customers in the TS-2 Pool. This will be calculated as follows:

Imbalance = Metered Usage - Delivered Volumes

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volumes}}$$

The term "day" or "daily" shall mean the period of twenty-four (24) consecutive hours beginning at 10:00 a.m. Eastern Clock Time.

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

The cash-out provision shall be applied against the aggregate volume of all Customers in a specific TS-2 Pool. The TS-2 Pool Manager will be responsible for the payment of the cash-out charges incurred by the TS-2 Pool as a result of imbalances under Rider TS-2.

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from TS-2 Pool Manager at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lowest daily mid-point price posted in "*Platts Gas Daily"* for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly negative imbalance percentage to be applied as follows:

When Total Net Negative Balance Percentage is:	The following percentage shall be multiplied by the above referenced "*Platts Gas Daily"* price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), TS-2 Pool Manager shall be billed for the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the highest daily mid-point price posted in "*Platts Gas Daily*" for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-referenced "*Platts Gas Daily*" price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	110%
>10% to ≤15%	120%
>15% to ≤20%	130%
>20%	140%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a TS-2 Pool Manager with a negative monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the TS-2 Pool Manager's bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rider.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

NOMINATIONS AND NOMINATED VOLUME

As further described below, TS-2 Pool Manager shall specify to Company the daily volume of gas required by the Customers in the TS-2 Pool. Such volume shall be stated in Mcf/day and converted to MMBtu/day.

At least ten (10) days prior to the beginning of each calendar month, TS-2 Pool Manager shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for the Pool Manager's TS-2 Pool.

Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by TS-2 Pool Manager to Company no later than 8:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from TS-2 Pool Manager daily nominations or changes thereto that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company.

Such volumes nominated by TS-2 Pool Manager shall include an allowance for Company's system average lost and unaccounted for gas ("LAUFG") expressed as a percentage and based on historical levels. Effective November 1, 2012, such LAUFG percentage is 3.52%. Such LAUFG percentage shall be revised annually each November 1 with notice provided to TS-2 Pool Manager at least thirty (30) days prior to such November 1. The volumes delivered by the TS-2 Pool Manager to Company for redelivery to Customers in the TS-2 Pool will be increased by TS-2 Pool Manager to cover the effective LAUFG percentage. For example, if the Customers in a TS-2 Pool require 325 Mcf on a given day, and the LAUFG% is 5.0%, then the Mcf nominated shall be 342 Mcf [325 / (1 - 0.05)]. The 342 Mcf shall be converted to MMBtu using a standard conversion factor as may be specified by Company from time to time. Such amount does not include any retention by the Pipeline Transporter. The volume nominated by the TS-2 Pool Manager to cover LAUFG shall not be considered in determining whether or not the TS-2 Pool Manager has exceeded the Pool Maximum Daily Quantity ("PMDQ") for the TS-2 Pool.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in a TS-2 Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rider TS-2, and no Customer shall participate in more than one pool concurrently. Except as provided for in Section 4 below, no Customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year.

2. To receive service hereunder, the PS-TS-2 Pool Manager shall enter into a PS-TS-2 Pool Management Agreement with Company. The PS-TS-2 Pool Management Agreement shall set forth the specific obligations of the TS-2 Pool Manager and Company under this rider.

   The TS-2 Pool Manager shall submit a signed PS-TS-2 Pool Management Agreement at least thirty (30) days prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the TS-2 Pool Manager of the date when service hereunder will commence. The Customers in the TS-2 Pool shall be set forth in Exhibit A of the PS-TS-2 Pool Management Agreement. In order to join a TS-2 Pool, Customer must have designated in writing its TS-2 Pool Manager as its agent pursuant to Rider TS-2. In order to modify the Customers in the pool, the Pool Manager must request a revised Exhibit A from Company and execute and return said exhibit at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective.

   The PMDQ shall be set forth in the Pool Management Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the TS-2 Pool. Company is not obligated to accept volumes for re-delivery on any day in excess of the PMDQ.

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3. The TS-2 Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure TS-2 Pool Manager's performance of its obligations under the PS-TS-2 Pool Management Agreement. In determining the level of the bond or other security to be required of a TS-2 Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customers in the TS-2 Pool, the general creditworthiness of the TS-2 Pool Manager, and the TS-2 Pool Manager's prior credit record with Company, if any. In the event that the TS-2 Pool Manager defaults on its obligations under this rider or the PS-TS-2 Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy TS-2 Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-TS-2 Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The PS-TS-2 Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if a TS-2 Pool Manager fails to meet any condition of this rider and/or Rider TS-2. The PS-TS-2 Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the TS-2 Pool Manager has payments in arrears. Written notice of termination of the PS-TS-2 Pool Management Agreement shall be provided both to the TS-2 Pool Manager and to the individual Customers in the TS-2 Pool by Company.

   Customers in the TS-2 Pool will be returned to sales service under the applicable rate schedule (CGS, IGS, or AAGS), or will be allowed to enroll in another TS-2 Pool.

5. Company shall directly bill the TS-2 Pool Manager for the PS-TS-2 Pool Administrative Charge, Action Alert Charges, and cash-out charges or payments contained in Rider TS-2. The monthly bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty-seven (27) days from the date of the bill then the TS-2 Pool Manager will be considered in default.

6. Company shall directly bill the individual Customers in the TS-2 Pool for all Administrative Charges, Distribution Charges, Pipeline Supplier's Demand Component Charges, Gas Cost True-Up Charges, Basic Service Charges, Minimum Annual Threshold Charges, Monthly Telemetry Charges, and other remote metering charges, as provided for in either Rider TS-2 or Customer's otherwise applicable sales rate schedule to which Rider TS-2 is a rider.

7. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

Standard Rate Rider **PS-TS**
Pooling Service – Rider TS T

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to "TS Pool Managers".

Rider PS-TS shall continue to be effective for customers who have previously elected to transport under Rider TS as of the effective date hereof. However, service hereunder shall terminate on October 31, 2013, at which point Rider PS-TS shall no longer be in effect. T T T

For the purpose of this rider a "TS Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rider TS to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties. T

RATE

In addition to any charges billed directly to TS Pool Manager or Customer as a result of the application of Rider TS or this rider, the following charge shall apply: T

PS-TS Pool Administrative Charge: $75 per customer in TS Pool per month T

CHARACTER OF SERVICE

Service under this rider allows a TS Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more standby sales transportation customers that comprise a PS-TS Pool.

The TS Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of customer(s) in the pool. The Cash-Out Provision of Rider TS shall be applied against the aggregate volume of all customers in a specific pool. The TS Pool Manager will be responsible for the payment of the PS-TS Pool Administrative Charge and any Monthly Cash-Out payments incurred by a specific pool as a result of imbalances under Rider TS. T T

SPECIAL TERMS AND CONDITIONS T

1. No customer shall participate in a TS Pool that does not individually meet the availability conditions of Rider TS, and no customer shall participate in more than one pool concurrently. Likewise, customers served under As-Available Gas Service Rate AAGS cannot be in the same pool with customers served under other sales rates. T

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Standard Rate Rider **PS-TS**

Pooling Service – Rider TS T

2. To receive service hereunder, the PS-TS Pool Manager shall enter into a PS-TS Pool Management Agreement with Company and shall submit a PS-TS Application/Agency Agreement for each member of the pool, signed by both Customer and its TS Pool Manager. The PS-TS Pool Management Agreement shall set forth the specific obligations of the TS Pool Manager and Company under this rider. The PS-TS Application/Agency Agreement shall set forth the members of the pool. T

   The TS Pool Manager shall submit a signed PS-TS Pool Management Agreement and a PS-TS Application/Agency Agreement for each member of the pool at least four (4) weeks prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the TS Pool Manager of the date when service hereunder will commence. A customer who terminates service under this rider or who desires to change TS Pool Managers shall likewise provide Company with a written notice at least four (4) weeks prior to the end of a billing period.

3. The TS Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure TS Pool Manager's performance of its obligations under the PS-TS Pool Management Agreement. To the extent that TS Pool Manager maintains a cash deposit with Company, Company shall refund such amount to TS Pool Manager, and TS Pool Manager shall provide Company with a surety bond, an irrevocable letter of credit, or other financial instrument satisfactory to Company in the amount determined by Company and at the time that such amount is next re-determined by Company. In determining the level of the bond or other security to be required of a TS Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of PS-TS Pool members, the general credit worthiness of the TS Pool Manager, and the TS Pool Manager's prior credit record with Company, if any. In the event that the TS Pool Manager defaults on its obligations under this rider or the PS-TS Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy TS Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-TS Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The TS Pool Manager shall provide Company with the written consent, in the form of a PS-TS Application/Agency Agreement, of all members to any change in the composition of the pool membership at least four weeks prior to the beginning of the first billing period that would apply to the modified pool. With the consent of the current pool members, the TS Pool Manager may provide written consent in the form of a PS-TS Application/Agency Agreement on behalf of the current pool members to any change in the composition of the pool. Without exception, any new pool member must provide its own written consent in the form of a PS-TS Application/Agency Agreement.

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Standard Rate Rider **PS-TS**
Pooling Service – Rider TS T

5. The PS-TS Pool Management Agreement will be terminated by Company upon four weeks written notice if a TS Pool Manager fails to meet any condition of this rider and/or Rider TS. The PS-TS Pool Management Agreement will also be terminated by Company upon four weeks written notice if the TS Pool Manager has payments in arrears. Written notice of termination of the PS-TS Pool Management Agreement shall be provided both to the TS Pool Manager and to the individual members of the pool by Company.

6. Company shall directly bill the TS Pool Manager for the PS-TS Pool Administrative Charge, monthly cash-out charges or payments contained in Rider TS. The monthly bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty-seven (27) days from the date of the bill then the TS Pool Manager will be considered in default.

7. Company shall directly bill the individual customers in the pool for all Distribution Charges, Basic Service Charges, and Administrative Charges as provided for in either Rider TS or Customer's otherwise applicable sales rate schedule to which Rider TS is a Rider.

Standard Rate Rider **PS-FT**

Pooling Service – Rate FT

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to “FT Pool Managers”.

For the purpose of this rider, a “FT Pool Manager” is defined as an entity which has been appointed by a customer or group of customers served under Rate FT to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties.

RATE

In addition to any charges billed directly to FT Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rate FT, the following charge shall apply to FT Pool Manager: T T T

PS-FT Pool Administrative Charge: $75 per Customer in FT Pool per month T

Other: In the event that FT Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then FT Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder. T

CHARACTER OF SERVICE

Service under this rider allows an FT Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more firm transportation customers that comprise a PS-FT Pool. Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT. It is the responsibility of the FT Pool Manager to convey OFOs to Customers in its FT Pool. T

The FT Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of Customers in the FT Pool. The FT Pool Manager shall be subject to the same nomination deadlines as set forth in Rate FT. The Daily Utilization Charge, OFO Penalty and cash-out provision of Rate FT shall be applied against the aggregate volume of all Customers in a specific FT Pool. The FT Pool Manager will be responsible for the payment of the PS-FT Pool Administrative Charge and any Daily Utilization Charges, OFO penalties or monthly cash-out payments incurred by a specific FT Pool as a result of imbalances under Rate FT. For purposes of this rider the Daily Utilization Charge shall apply to daily imbalances that exceed ±2%, instead of the ±5% otherwise applicable in Rate FT. Company shall issue an Operational Flow Order as set forth in Rate FT to the FT Pool Manager during periods when service cannot be provided to meet daily imbalances. T T

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Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in an FT Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rate FT, and no customer shall participate in more than one FT Pool concurrently. Unless a Customer meets the provisions of the Remote Metering requirement under Rate FT, that Customer shall not participate in an FT Pool.

2. To receive service hereunder, the FT Pool Manager shall enter into a PS-FT Pool Management Agreement with Company and shall submit a PS-FT Application/Agency Agreement for each Customer in the FT Pool, signed by both Customer and its FT Pool Manager. The PS-FT Pool Management Agreement shall set forth the specific obligations of the FT Pool Manager and Company under this rider. The PS-FT Application/Agency Agreement shall set forth the Customers in the FT Pool.

   The FT Pool Manager shall submit a signed PS-FT Pool Management Agreement and a PS-FT Application/Agency Agreement for each Customer in the FT Pool at least thirty (30) days prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the FT Pool Manager of the date when service hereunder will commence. A Customer who terminates service under this rider or who desires to change FT Pool Managers shall likewise provide Company with a written notice at least thirty (30) days prior to the end of a billing period.

   The Pool Maximum Daily Quantity ("PMDQ") shall be set forth in the Pool Management Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the FT Pool. Company is not obligated to accept volumes for re-delivery on any day in excess of the PMDQ.

3. The FT Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure FT Pool Manager's performance of its obligations under the PS-FT Pool Management Agreement. In determining the level of the bond or other security to be required of an FT Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customers in the FT Pool, the general creditworthiness of the FT Pool Manager, and the FT Pool Manager's prior credit record with Company, if any. In the event that the FT Pool Manager defaults on its obligations under this rider or the PS-FT Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable

letter of credit, or other financial instrument to satisfy FT Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-FT Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner. T

4. The FT Pool Manager shall provide Company with the written consent, in the form of a PS-FT Application/Agency Agreement, of all Customers to any change in the composition of the Customers in the FT Pool at least thirty (30) days prior to the beginning of the first billing period that would apply to the modified FT Pool Such written consent for existing Customers in the FT Pool to any change in the composition of the FT Pool may be made by the FT Pool Manager as Agent for the current Customers in the FT Pool. Without exception, any new Customer in the FT Pool must provide its own written consent in the form of a PS-FT Application/Agency Agreement.

5. The PS-FT Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if an FT Pool Manager fails to meet any condition of this rider and/or Rate FT. The PS-FT Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the FT Pool Manager has payments in arrears. Written notice of termination of the PS-FT Pool Management Agreement shall be provided both to the FT Pool Manager and to the individual Customers in the FT Pool by Company.

6. Company shall directly bill the FT Pool Manager for the PS-FT Pool Administrative Charge, Utilization Charge for Daily Imbalances, cash-out charges or payments, and OFO Charges contained in Rate FT. The bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty seven (27) days from the date of the bill, then the FT Pool Manager will be considered in default.

7. Company shall directly bill the individual customers in the FT Pool for all Distribution Charges, Administrative Charges, Gas Cost True-Up Charges, Minimum Daily Threshold Charges, and remote metering charges or payments provided for in Rate FT. T T T

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 main extensions or to other facilities which are necessary to provide basic gas 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. Customers currently being served under the Excess Facilities Rider pursuant to Original Sheet No. 52 of LG&E's Tariff PSC. of Ky. Gas No. 6, shall continue to be served thereunder.

DEFINITION OF EXCESS FACILITIES

Excess facilities are equipment and devices which are installed in addition to or in substitution for the normal facilities required to render basic gas service and where such facilities are T
dedicated to a specific customer. Applications of excess facilities include, but are not limited to, T
redundant gas regulator capacity; gas filters/separators; odorant removal systems; gas compression equipment; indirect heaters; gas purification systems; additional facilities required for the customer to take service from a high-pressure gas line; and any other equipment/systems not normally installed to provide gas service to a customer.

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 1.29% 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 0.48% T/R

PAYMENT

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

TERM OF CONTRACT

The initial term of contract to 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.

Gas Line Tracker

APPLICABLE

Applicable to all customers receiving service under the Company's Rate Schedules RGS, VFD, CGS, IGS, AAGS, and DGGS.

CALCULATION OF THE GAS LINE TRACKER REVENUE REQUIREMENT

The GLT Revenue Requirement includes the following:

a. GLT related Plant In-Service not included in base gas rates minus the associated GLT related accumulated depreciation and accumulated deferred income taxes;
b. Retirement and removal of plant related to GLT construction;
c. The rate of return on the net rate base is the overall rate of return on capital authorized in the Company's latest base gas rate case, grossed up for federal and state income taxes;
d. Depreciation expense on the GLT-related Plant In-Service less retirement and removals; and
e. Incremental Operation and Maintenance

GLT PROGRAM FACTORS

All customers receiving service under rate schedules RGS, VFD, CGS, IGS, AAGS, and DGGS shall be assessed an adjustment to their applicable rate schedule that will enable the Company to recover the costs associated with the GLT program. After the Company replaces a gas service riser or a gas service line under this program, it will assume ownership and responsibility for the plant and equipment. The allocation of the program cost to customers will be in proportion to their relative base revenue share approved in Case No. 2012-00222.

A filing to update the projected program costs will be submitted annually at least two (2) months prior to the beginning of the effective period. The filing will reflect the anticipated impact on the Company's revenue requirements of net plant additions expected during the upcoming year. After the completion of a plan year, the Company will submit a balancing adjustment to true up the actual costs with the projected program costs for the preceding year. Such adjustment to the GLT will become effective with the first billing cycle on or after the effective date of such change.

GLT RATES

The charges for the respective gas service schedules for the first billing cycle of January 2013 are:

RGS – Residential Gas Service	$ 2.35
VFD – Volunteer Fire Department Service	$ 2.35
CGS – Commercial Gas Service	$ 11.60
IGS – Industrial Gas Service	$ 93.25
AAGS – As-Available Gas Service	$514.23
DGGS – Distributed Generation Gas Service	$ 0

Adjustment Clause **GSC**
Gas Supply Clause

APPLICABLE TO
All gas sold.

GAS SUPPLY COST COMPONENT (GSCC)

Gas Supply Cost	$0.36785
Gas Cost Actual Adjustment (GCAA)	(0.01182)
Gas Cost Balance Adjustment (GCBA)	(0.01593)

Refund Factors (RF) continuing for twelve months from the effective date of each or until Company has discharged its refund obligation thereunder:

Refund Factor Effective August 1, 2011	(0.00043)
Refund Factor Effective November 1, 2011	(0.00044)
Refund Factor Effective February 1, 2012	(0.00041)
Refund Factor Effective May 1, 2012	(0.00044)
Total Refund Factor	(0.00172)

Performance-Based Rate Recovery Component (PBRRC)	0.01066
Total Gas Supply Cost Component Per 100 Cubic Feet (GSCC)	$0.34904

Adjustment Clause **GSC**

Gas Supply Clause

The bill amount computed under each of the rate schedules to which this Gas Supply Clause is applicable shall include a Gas Supply Cost Component per 100 cubic feet of consumption calculated for each three-month period in accordance with the following formula:

GSCC = Gas Supply Cost + GCAA + GCBA + RF + PBRRC

where:

Gas Supply Cost is the expected average cost per 100 cubic feet for each three-month period (beginning February 1, May 1, August 1, or November 1, as the case may be) determined by dividing the sum of the monthly gas supply costs by the expected deliveries to customers. Monthly gas supply cost is composed of the following:

(a) Expected purchased gas costs (gas supply and pipeline transportation) for system supply, minus

(b) Portion of such expected purchased gas costs expected to be used for non-Gas Department purposes, minus

(c) Portion of such expected purchased gas cost expected to be injected into underground storage, plus

(d) Expected underground storage withdrawals at the average unit cost of working gas contained therein;

(GCAA) is the Gas Cost Actual Adjustment per 100 cubic feet which compensates for differences between the previous three-month period's expected gas cost and the actual cost of gas during that three-month period, plus carrying charges on any over- or under-recoveries at the Company's weighted average cost of capital, plus net uncollectible gas cost portion of bad debt.

(GCBA) is the Gas Cost Balance Adjustment per 100 cubic feet which compensates for any under- or over-collections which have occurred as a result of prior adjustments, plus carrying charges on any over- or under-recoveries at the Company's weighted average cost of capital.

(RF) is the sum of the Refund Factors set forth on Sheet No. 85 of this Tariff.

(PBRRC) is the amount per 100 cubic feet calculated pursuant to the Experimental Performance-Based Rate Mechanism contained in the Adjustment Clause PBR. The PBRRC is determined for each 12-month PBR period ended October 31.

Company shall file a revised Gas Supply Cost Component (GSCC) every three months giving effect to known changes in the wholesale cost of all gas purchases and the cost of gas deliveries from underground storage. The Company may make out-of-time filings when warranted. Such filing shall be made at least thirty (30) days prior to the beginning of each three-month period and shall include the following information:

1. A copy of the tariff rate(s) of Company's pipeline transporter(s) applicable to such three-month period.

2. A statement, through the most recent three-month period for which figures are available, setting out the accumulated costs recovered hereunder compared to actual gas supply costs recorded on the books. T T T

3. A statement setting forth the supporting calculations of the Gas Supply Cost and the Gas Cost Actual Adjustment (GCAA) and the Gas Cost Balance Adjustment (GCBA) applicable to such three-month period.

To allow for the effect of Company's cycle billing, each change in the GSCC shall be placed into effect with service rendered on and after the first day of each three-month period.

Company may file at least twenty (20) days prior to the beginning of any month a reduction in the Gas Supply Cost Component to reflect a reduction in expected purchased gas costs to remain in effect for the remainder of the quarter. T T T

In the event that Company receives from its supplier a cash refund of amounts paid to such supplier with respect to a prior period, Company will make adjustments in the amounts charged to its customers under this provision, as follows: T

1. The "Refundable Amount" shall be the amount received by Company as a refund less any portion thereof applicable to gas purchased for electric energy production plus interest at a rate equal to the average of the "3-month commercial paper rate" for the immediately preceding 12-month period, less ½ of 1 percent to cover the cost of refunding in accordance with the Order of the Commission in Case No. 7799-D. Such Refundable Amount shall be divided by the number of hundred cubic feet of gas that Company estimates it will sell to its customers during the twelve-month period which commences with implementation of the next Gas Supply Clause filing, thus determining a "Refund Factor." T T T T

2. Effective with the implementation of the next Gas Supply Clause filing, Company will reduce, by the Refund Factor so determined, the Gas Supply Cost Component that would otherwise be applicable during the subsequent twelve-month period. Provided, however, that the period of reduced Gas Supply Cost Component will be adjusted, if necessary, in order to refund, as nearly as possible, the Refundable Amount.

3. In the event of any large or unusual refunds, Company may apply to the Public Service Commission of Kentucky for the right to depart from the refund procedure herein set forth.

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to Residential Gas Service Rate RGS, Volunteer Fire Department Rate VFD, Firm Commercial Gas Service Rate CGS, Firm Industrial Gas Service Rate IGS, As-Available Gas Service Rate AAGS, Firm Gas Transportation Rate FT, and Gas Transportation Service/Standby Rider TS, and Gas Transportation Service/Firm Balancing Rider TS-2. Any T
industrial gas customer who also receives electric service from the Company as an industrial T
customer, and has elected not to participate in a demand-side management program T
hereunder, shall not be assessed a charge pursuant to this mechanism. 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 100 cubic feet (Ccf) of monthly gas 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 Ccf sales for the upcoming twelve-month period to determine the DCR for 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 Ccf) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per Ccf for purposes of determining the lost revenue to be recovered hereunder for each customer class. The non-variable revenue requirement is defined as the weighted average price per Ccf of expected Distribution Cost Component billings for the customer classes.

2. The lost revenues for each customer class shall then be divided by the estimated class sales (in Ccf) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenues from lost sales calculated for a twelve-month period shall be included in the DRLS for thirty-six (36) months or until implementation of new rates pursuant to a general rate case. For recovery purposes, the lost sales revenues will be assigned 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 shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DSMI. 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 determined by calculating the difference between the amount billed during the twelve-month period from application of the DBA unit charges 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 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 balance adjustment amounts, plus interest, shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DBA for each 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

The filing of modifications to the DSMRC that require changes in the DCR component shall be made at least two (2) months prior to the beginning of the effective period for billing. Modifications to other components of the DSMRC shall be made at least thirty (30) 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 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 RGS and VFD Standard Gas Rate Schedules.

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 LG&E'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 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. LG&E will reimburse the cost of plan reviews and inspection costs related to an Energy Star or HERS home certification.

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 CGS, IGS, AAGS, FT, TS, and TS-2 Standard T
Gas Rate Schedules and Riders. T

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

Monthly Adjustment Factors:

Residential Rate RGS and Volunteer Fire Department Rate VFD	Energy Charge	
DSM Cost Recovery Component (DCR)	$ 0.01210 per Ccf	
DSM Revenues from Lost Sales (DRLS)	$ 0.00241 per Ccf	
DSM Incentive (DSMI)	$ 0.00054 per Ccf	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00554 per Ccf	
DSM Balance Adjustment (DBA)	$ (0.00350) per Ccf	
Total DSMRC for Rates RGS and VFD	$ 0.01709 per Ccf	

Commercial Customers Served Under Firm Commercial Gas Service Rate CGS, As-Available Gas Service Rate AAGS, Firm Transportation Rate FT, Gas Transportation Service/Standby Rider TS, and Gas Transportation Service/Firm Balancing Service Rider TS-2	Energy Charge	T T
DSM Cost Recovery Component (DCR)	$ 0.00077 per Ccf	
DSM Revenues from Lost Sales (DRLS)	$ 0.00000 per Ccf	
DSM Incentive (DSMI)	$ 0.00000 per Ccf	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00052 per Ccf	
DSM Balance Adjustment (DBA)	$ 0.00008 per Ccf	
Total DSMRC for Rates CGS, AAGS, FT, TS, and TS-2	$ 0.00137 per Ccf	T

Adjustment Clause **PBR**

Experimental Performance Based Rate Mechanism

APPLICABLE

To all gas sold.

RATE MECHANISM

The monthly amount computed under each of the rate schedules to which this Performance Based Ratemaking Mechanism is applicable shall be increased or decreased by the Performance Based Rate Recovery Component **(PBRRC)** at a rate per 100 cubic feet (Ccf) of monthly gas consumption. Demand costs and commodity costs shall be accumulated separately and included in the Pipeline Supplier's Demand Component and the Gas Supply Cost Component of the Gas Supply Clause (GSC), respectively. The PBRRC shall be determined for each 12-month period ended October 31 during the effective term of this experimental performance based ratemaking mechanism, which 12-month period shall be defined as the PBR period.

The PBRRC shall be computed in accordance with the following formula:

$$\mathbf{PBRRC} = \frac{\mathbf{CSPBR + BA}}{\mathbf{ES}}$$

Where:

ES = Expected Ccf sales, as reflected in Company's GSC filing for the upcoming 12-month period beginning February 1.

CSPBR = Company Share of Performance Based Ratemaking Mechanism savings or expenses. The CSPBR shall be calculated as follows:

$$\mathbf{CSPBR = TPBRR \times ACSP}$$

Where:

TPBRR = Total Performance Based Ratemaking Results. The TPBRR shall be savings or expenses created during the PBR Period. TPBRR shall be calculated as follows:

$$\mathbf{TPBRR = (GAIF + TIF + OSSIF)}$$

GAIF

GAIF = Gas Acquisition Index Factor. The GAIF shall be calculated by comparing the total annual Benchmark Gas Costs **(BGC)** for system supply natural gas purchases for the PBR period to the total annual Actual Gas Costs **(AGC)** for system supply natural gas purchases during the same period to determine if any Shared Expenses or Shared Savings exist.

The BGC shall include two benchmark components as follows:

$$\mathbf{BGC = TABMGCC + HRF}$$

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

Where:

TABMGCC represents the Total Annual Benchmark Gas Commodity Costs and is the annual sum of the monthly Benchmark Gas Commodity Costs **(BMGCC)** of gas purchased for system supply; and

HRF represents Historical Reservation Fees and is an annual dollar amount equal to Company's average annual supply reservation fees based on the 24-month period ended October 31 immediately preceding the PBR period.

BMGCC represents Benchmark Gas Commodity Costs and shall be calculated on a monthly basis and accumulated for the PBR period. BMGCC shall be calculated as follows:

BMGCC = Sum {[SZFQE%i x (APV - PEFDCQ)x SAIi]} + [PEFDCQ x DAI]

Where:

SZFQE% is the Supply Zone Firm Quantity Entitlement Percentage derived from Company's firm entitlements by pipeline and by zone for which indices are posted. The percentage represents the pro-rata portion of Company's firm lateral and mainline receipt point quantity entitlements by zone for each transportation contract by pipeline.

i represents each supply area.

APV is the actual purchased volumes of natural gas for system supply for the month. The APV shall include purchases necessary to cover retention volumes required by the pipeline as fuel.

PEFDCQ are the Purchases In Excess of Firm Daily Contract Quantities delivered to Company's city gate. Firm Daily Contract Quantities are the maximum daily contract quantities which Company can deliver to its city gate under its various firm transportation agreements and arrangements.

SAI is the Supply Area Index factor to be established for each supply area in which Company has firm transportation entitlements used to transport its natural gas purchases and for which price postings are available. The five supply areas are TGT-SL (Texas Gas Transmission - Zone SL), TGT-1 (Texas Gas Transmission - Zone 1), TGT-4 (Texas Gas Transmission – Zone 4), TGPL-0 (Tennessee Gas Pipeline - Zone 0), and TGPL-1 (Tennessee Gas Pipeline - Zone 1).

The monthly SAI for TGT-SL, TGT-1, TGT-4, TGPL-0 and TGPL-1 shall be calculated using the following formula:

SAI = [I(1) + I(2) + I(3)] / 3

DAI is the Delivery Area Index to be established for purchases made by Company when Company has fully utilized its pipeline quantity entitlements on a daily basis and which are for delivery to Company's city gate from either Texas Gas Transmission's Zone 4 or Tennessee Gas Pipeline's Zone 2.

The monthly DAI for TGT-4 and TGPL-2 shall be calculated using the following formula:

DAI = [I(1) + I(2) + I(3)] / 3

Where:

I represents each index reflective of both supply area prices and price changes throughout the month in these various supply areas.

The indices for each supply zone are as follows:

SAI (TGT-SL)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for Louisiana - Onshore South Texas Gas Zone SL averaged for the month. T

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas Zone SL. T

SAI (TGT-1)

I(1) is the average of weekly *Natural Gas Week* postings for North Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for East Texas - North Louisiana Area -Texas Gas Zone 1 averaged for the month. T

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas Zone1. T

SAI (TGT-4)

I(1) is the average of weekly *Natural Gas Week* postings for Spot Prices on Interstate Pipeline Systems for Lebanon Hub.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for Appalachia – Lebanon Hub averaged for the month. T

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Northeast – Lebanon Hub. T

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

SAI (TGPL-0)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Texas as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for South – Corpus Christi-Tennessee averaged for the month. T

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee Zone 0. T

SAI (TGPL-1)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for Louisiana – Onshore South – Tennessee 500 Leg averaged for the month. T

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee 500 leg. T

DAI (TGT-4) and (TGPL-2)

I(1) is the average of weekly *Natural Gas Week* postings for Spot Prices on Interstate Pipeline Systems for Dominion - South.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for the Daily Price Survey for Appalachia - Dominion South Point. T

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Prices of Spot Gas Delivered to Pipeline for Dominion Transmission Inc. - Appalachia. T

AGC represents Company's total annual Actual Gas Costs of natural gas purchased for system supply and is equal to the total monthly actual gas commodity costs and supply reservation fees plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments paid by Company to its suppliers accumulated for the PBR period. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

To the extent that AGC exceeds BGC for the PBR period, then the GAIF Shared Expenses shall be computed as follows:

Shared Expenses = AGC - BGC

To the extent that AGC is less than BGC for the PBR period, then the GAIF Shared Savings shall be computed as follows:

Shared Savings = BGC – AGC

TIF

TIF = Transportation Index Factor. The Transportation Index Factor shall be calculated by comparing the Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** of natural gas transportation services during the PBR period, to the Total Annual Actual Gas Transportation Costs **(TAAGTC)** applicable to the same period to determine if any Shared Expenses or Shared Savings exist.

The Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** are calculated as follows:

TABMGTC = Annual Sum of Monthly BMGTC

Where:

BMGTC is the Benchmark Monthly Gas Transportation Costs which include both demand and volumetric costs associated with natural gas pipeline transportation services. The BMGTC shall be accumulated for the PBR period and shall be calculated as follows:

BMGTC = Sum [BM(TGT) + BM(TGPL) + BM(PPL)]

Where:

BM(TGT) is the benchmark associated with Texas Gas Transmission Corporation.

BM(TGPL) is the benchmark associated with Tennessee Gas Pipeline Company.

BM(PPL) is the benchmark associated with a proxy pipeline. The appropriate benchmark, which will be determined at the time of purchase, will be used to benchmark purchases of transportation capacity from non-traditional sources.

The benchmark associated with each pipeline shall be calculated as follows:

BM(TGT) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(TGPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(PPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

Where:

TPDR is the applicable Tariffed Pipeline Demand Rate.
DQ is the Demand Quantities contracted for by Company from the applicable transportation provider.

TPCR is the applicable Tariffed Pipeline Commodity Rate.

AV is the Actual Volumes delivered at Company's city-gate by the applicable transportation provider for the month.

S&DB represents Surcharges, Direct Bills and other applicable amounts approved by the Federal Energy Regulatory Commission (FERC). Such amounts are limited to FERC-approved charges such as surcharges, direct bills, cashouts, take-or-pay amounts, Gas Supply Realignment and other Order 636 transition costs.

The Total Annual Actual Gas Transportation Costs (**TAAGTC)** paid by Company for the PBR period shall include both demand and volumetric costs associated with natural gas pipeline transportation services as well as all applicable FERC-approved surcharges, direct bills and cash-outs included in S&DB, plus the gains and/or losses from the use of financial T
hedging instruments and the financial transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

To the extent that TAAGTC exceeds TABMGTC for the PBR period, then the TIF Shared Expenses shall be computed as follows:

Shared Expenses = TAAGTC – TABMGTC

To the extent that TAAGTC is less than TABMGTC for the PBR period, then the TIF Shared Savings shall be computed as follows:

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

Shared Savings = TABMGTC - TAAGTC

Should one of Company's pipeline transporters file a rate change effective during any PBR period and bill such proposed rates subject to refund, the period over which the benchmark comparison is made for the relevant transportation costs will be extended for one or more 12-month periods, until the FERC has approved final settled rates, which will be used as the appropriate benchmark. Company will not share in any of the savings or expenses related to the affected pipeline until final settled rates are approved.

OSSIF

OSSIF = Off-System Sales Index Factor. The Off-System Sales Index Factor shall be equal to the Net Revenue from Off-System Sales **(NR)**.

Net Revenue is calculated as follows:

NR = OSREV - OOPC

Where:

OSREV is the total revenue associated with off-system sales and storage service transactions.

OOPC is the out-of-pocket costs associated with off-system sales and storage service transactions, and shall be determined as follows:

OOPC = OOPC(GC) + OOPC(TC) + OOPC(SC) + OOPC(UGSC) + Other Costs

Where:

OOPC(GC) is the Out-of-Pocket Gas Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm supply contracts, the OOPC(GC) shall be the incremental cost to purchase the gas available under Company's firm supply contracts. For off-system sales not using Company's firm supply contracts, the OOPC(GC) shall be the incremental costs to purchase the gas from other entities.

OOPC(TC) is the Out-of-Pocket Transportation Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm transportation agreements, the OOPC(TC) shall be the incremental cost to use the transportation available under Company's firm supply contracts. For off-system sales not using Company's firm transportation agreements, the OOPC(TC) shall be the incremental costs to purchase the transportation from other entities.

OOPC(SC) is the Out-of-Pocket Storage Costs associated with off-system sales of storage. If this is gas in Company's own storage it shall be priced at the average price of the gas in Company's storage during the month of the sale. If this is gas from the storage component of Texas Gas's No-Notice Service, this gas shall be priced at the replacement cost.

OOPC(UGSC) is the Out-of-Pocket Underground Storage Costs associated with off-system sales of storage services. For the off-systems sales of storage services utilizing Company's on-system storage, the OOPC(UGSC) shall include incremental storage losses, odorization, and other fuel-related costs such as purification, dehydration, and compression. Such costs shall exclude labor-related expenses.

Other Costs represent all other incremental costs and include, but are not limited to, costs such as applicable sales taxes and excise fees plus the gains and/or losses from the use of financial hedging instruments and the transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

ACSP

ACSP = Applicable Company Sharing Percentage. The ACSP shall be determined based on the PTAGSC.

Where:

PTAGSC = Percentage of Total Actual Gas Supply Costs. The PTAGSC shall be the TPBRR stated as a Percentage of Total Actual Gas Supply Costs and shall be calculated as follows:

$$\mathbf{PTAGSC} = \frac{\mathbf{TPBRR}}{\mathbf{TAGSC}}$$

Where:

TAGSC = Total Actual Gas Supply Costs. The TAGSC shall be calculated as follows:

$$\mathbf{TAGSC = AGC + TAAGTC}$$

If the absolute value of the PTAGSC is less than or equal to 4.5%, then the ACSP of 25% shall be applied to TPBRR to determine CSPBR. If the absolute value of the PTAGSC is greater than 4.5%, then the ACSP of 25% shall be applied to the amount of TPBRR that is equal to 4.5% of TAGSC to determine a portion of CSPBR, and the ACSP of 50% shall be applied to the amount of TPBRR that is in excess of 4.5% of TAGSC to determine a portion of CSPBR. These two portions are added together to produce the total CSPBR.

BA

BA = Balance Adjustment. The BA is used to reconcile the difference between the amount of revenues billed or credited through the CSPBR and previous application of the BA and revenues which should have been billed or credited, as follows:

1) For the CSPBR, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the CSPBR and the actual amount used to establish the CSPBR for the period.

2) For the BA, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the BA and the actual amount used to establish the BA for the period.

Review

Within 60 days of the end of the fourth year of the five-year extension, Company will file an assessment and review of the PBR mechanism for the first four years of the five-year extension period. In that report and assessment, Company will make any recommended modifications to the PBR mechanism.

WEATHER NORMALIZATION ADJUSTMENT (WNA)

The sales to Residential and Commercial Customers under Rate Schedules RGS and CGS shall be increased or decreased monthly by an amount hereinafter described as the Weather Normalization Adjustment (WNA).

Determination of WNA

Weather normalized volumes shall be utilized during the November through April billing periods to calculate the non-gas portion of the bills of all heating Customers served under Rate Schedules RGS and CGS. During the remainder of the year, May through October, the bills shall be computed based on actual consumption.

Weather Normalization Adjustment will be calculated using the following formula:

WNA = [(Actual Mcf - Base Load Mcf) * (Normal Degree Days/Actual Degree Days)]

Each Customer's base load will be determined individually, and will be recomputed annually. Rates used in the computation of the WNA shall be determined based on the applicable base rate charge as set forth on the RGS and CGS Rate Schedules.

Adjustment Clause

Franchise Fee

APPLICABILITY

All gas rate schedules.

MONTHLY CHARGE

A surcharge shall be calculated and added to the total bill for gas service for all customers located within local governmental jurisdictions which currently or in the future impose municipal franchise fees or other local taxes on the Company by ordinance, franchise, or otherwise. Such fees or taxes shall be net of any corresponding fees or taxes which are currently included in the base charges of each rate schedule.

The amount calculated shall be applied exclusively to the bills of customers receiving service within the territorial limits of the authority imposing the fee or tax. The fee or tax shall be added to the customer's bill as a separate item. Where more than one such fee or tax is imposed, each of the fees or taxes applicable to each customer shall be added to the bills as separately identified items.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

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

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 gas 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 gas 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 gas 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 gas 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 gas 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 gas 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 gas service is clearly outside the scope of Company's standard rate schedules, Company may establish special terms and require special contracts giving effect to such unusual circumstances.

TRANSFER OF APPLICATION

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

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, the 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 months.

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 Customers 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.

TERMS AND CONDITIONS

Customer Responsibilities

CUSTOMER’S EQUIPMENT AND INSTALLATION.

Customer shall furnish, install, and maintain at Customer’s expense the necessary Customer's Service Line extending from Company's Service Connection at the property line to the building or place of utilization of the gas.

All piping, appliances, and other gas equipment and apparatus, except the meter, regulator, and any gas riser or service line the Company has installed, repaired, or replaced, located on and within the Customer's premises beyond point of connection with Company's Service Connection at the property line shall be furnished and installed by and at the expense of Customer, and shall be maintained by Customer in good and safe condition. Company assumes no responsibility whatsoever for the condition of Customer's piping, apparatus or appliances, nor for the maintenance or renewal of any portion thereof. T T

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 gas service or for the purpose of turning on and shutting off the gas supply 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.

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

Gas service shall not be used for purposes other than as set forth in customer's application or contract.

TERMS AND CONDITIONS

Customer Responsibilities

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EXCLUSIVE SERVICE ON INSTALLATION CONNECTED (continued)

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company.

LIABILITY

Customer assumes all responsibility for the gas service upon Customer's premises at and from the point of delivery of gas and for the pipes 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 gas, occasioned by such gas or said pipes 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 pipes, meters, and appurtenances supplied by Company for the rendition of gas service to its customers have a definite capacity. 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, regulators, or other equipment of Company caused by such material increase in Customer's connected load.

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 mains, Customer shall obtain from the proper owner or owners the necessary consent to the installation and maintenance in said premises and across such intervening property of Customer's piping and facilities required for the supply of gas 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.

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

COMPANY-OWNED SERVICE LINES T

The Company will install, own, operate and maintain the service line at the premises of residential and commercial customers, if such premises are not connected to a Company main by a service line. With respect to residential and commercial customers that occupy premises already connected to a Company main by a service line that the Company has installed, repaired, or replaced, the Company shall be responsible for operating and maintaining the customer service line and when the Company determines that replacement of such customer service line is necessary the Company shall be responsible for installing the service line and shall thereafter own the service line.

Any customer accepting gas service under this section shall be deemed to have granted the Company an easement across his property for such service. No service line shall be installed across private property other than the premises of the building to be supplied with gas, except after special investigation and approval by the Company.

When the length of the service pipe required between the property line and the meter is 100 feet or less, the Company will assess no charge for the service pipe installation.

When the length of required service pipe exceeds 100 feet, the Company may require the applicant to contribute toward the cost of the service line installation an amount equal to the estimated cost per foot for each lineal foot of service beyond 100 feet. Contributions by customers toward the Company's cost of furnishing and installing service lines in accordance with this section are non-refundable.

In the event that the Company is required to undertake any excavation on a customer's property in connection with the installation, repair, maintenance or replacement of a service line, the Company shall make reasonable efforts to restore the property to its original condition pursuant to generally accepted utility standards for such construction operations.

TERMS AND CONDITIONS

Company Responsibilities

METERING

The gas 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 GAS

The point of delivery of gas supplied by Company shall be at the point where the gas passes from the pipes of Company's Service Connection into Customer's Service Line, irrespective of the location of the metering and regulating equipment.

If the Service Line is owned by the Customer, the point of delivery of gas supplied by the T
Company shall be at the point where the gas passes from the pipes of Company's Service Connection into Customer's Service Line, irrespective of the location of the metering and regulation equipment.

If the Service Line is owned by the Company, the point of delivery of gas supplied by the Company shall be at the point where the gas passes from the outlet of the meter to the Customer's yard line or house piping.

COMPANY'S EQUIPMENT AND INSTALLATION

The Company shall furnish, install, and maintain at its expense the necessary service T
connection. The location of this service connection will be made at the discretion and judgment of the Company.

The Company will furnish, install, and maintain at its expense the necessary meter, regulator, and connections which will be located at or near the building, at the discretion or judgment of the Company. Suitable site or location for the meter, meter stand (including meter riser), and regulator and connections shall be provided by the Customer and title to this equipment shall remain in the Company with the right to install, operate, maintain, and remove same and no charge shall be made by the Customer for use of the premises as occupied or used. 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 a reasonable form of easement agreement, if requested by Company. T

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 gas requirements.

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TERMS AND CONDITIONS

Company Responsibilities

COMPANY NOT LIABLE FOR INTERRUPTIONS T

Company will exercise reasonable care and diligence in an endeavor to supply gas service continuously and without interruption, except as provided in the terms of certain rate schedules; however, Company does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay or failure of gas 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 gas service delivered at Company's property line, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or property of the Customer or of third persons resulting from the presence, use or abuse of gas on the Customer's premises or resulting from defects in or accidents to any of Customer's piping, 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 the Customer or any other party affected by the gas 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.

OBLIGATION TO SERVE T

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company.

SPECIAL RULES FOR CUSTOMERS SERVED FROM HIGH PRESSURE MAINS, GAS TRANSMISSION MAINS, AND STORAGE GATHERING LINES

In order to ensure the integrity, safe operations, and reliability of the Company's gas system, these special rules apply to customers served from high pressure mains, gas transmission mains, and storage gathering lines.

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TERMS AND CONDITIONS

Customer Responsibilities

When a customer requests service from a high pressure main, gas transmission main, or storage gathering line under Rate RGS, CGS, IGS, VFD, AAGS, or FT, Company shall determine, in its sole discretion, if service is justified, feasible, and consistent with good operating practice. T

Upon approval by Company of a request by a customer (or group of customers) for service from a high pressure main, gas transmission main, or storage gathering line, then Company may charge the customer (or group of customers) in addition to the charges under the applicable rate schedule, the estimated installed cost of the tap, any regulation equipment, piping, and any other equipment or facilities determined by Company, in its sole discretion, to be necessary to provide such service consistent with good operating practice.

In no case, shall Company be obligated to provide service to customers served under Rate DGGS from a high pressure main, gas transmission main, or storage gathering line.

TERMS AND CONDITIONS

Character of Service

HEATING VALUE

Company will normally supply natural gas having a heating value of approximately 1,000 Btu per cubic foot or as is otherwise supplied by the interstate pipeline(s) from which Company takes natural gas service. All gas received into the system of Company shall meet either of the applicable quality standards of the interstate pipeline delivering natural gas to Company or the lowest standard if there is more than one pipeline. Company reserves the right to refuse to accept gas from any entity whose gas does not meet those minimum standards. When it is necessary to supplement the supply of natural gas, Company reserves the right, at its discretion, to supplement its supply of natural gas with a mixture of vaporized liquefied petroleum gas and air.

STANDARD PRESSURE AND MEASUREMENT BASE

The standard distribution pressure of the gas supplied by Company is four ounces per square inch above atmospheric pressure.

Atmospheric pressure shall be assumed in all cases to be 14.5 pounds per square inch and temperature shall be assumed to be 60 degrees Fahrenheit; provided, however, Company reserves the right for billing purposes to correct as necessary the actual temperature to a 60 degree Fahrenheit basis in the case of large volume customers.

All gas measured at pressures higher than the standard pressure shall be converted to a pressure base of 14.73 pounds per square inch absolute for billing purposes.

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 electric or gas 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.

Where Company serves a customer with both electric and gas service at the same service location, Company will render a combined bill. However, a residential customer may request, and Company will render, separate bills under the following conditions: (1) Customer is being threatened with disconnection for non-payment or has already been disconnected for that reason and (2) Customer would be able to pay either the gas or electric portion of his bill and thus retain one service.

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 the 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.

TERMS AND CONDITIONS

Billing

READING OF SEPARATE METERS NOT COMBINED

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

CUSTOMER RATE MIGRATION T

Unless otherwise specified in the applicable rate schedule or rider, 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.

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 the Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of the Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, Company may contact Customer by telephone or in writing 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, or known leaks in the Customer's service line. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether it shows an average error greater than 2 percent fast or slow. Company will notify the customers of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 10(4) and (5). In addition to the annual monitoring, Company will immediately investigate usage deviations brought to its attention as a result of its on-going meter reading or billing processes or customer inquiry.

RESALE OF GAS

Gas service furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such gas to any other person, firm, or corporation on 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.

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 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.
5) The General Terms and Conditions regarding Deposits set forth above shall not apply to, and shall be superseded by, the deposit requirements set forth in Section 3 of the Special Terms T
and Conditions contained in Standard Rate Rider PS-TS-2 (Sheet No. 59.5), Standard Rate T
Rider PS-TS (Sheet No. 60.1), and Standard Rate Rider PS-FT (Sheet No. 61.1). T

RESIDENTIAL

1) Residential customers are those customers served under Residential Gas Service, Sheet No. 5.
2) The deposit for a residential customer is in the amount of $95.00, which is calculated in R
accordance with 807 KAR5:006, Section 7(1)(b). For combination gas and electric customers, the total deposit will be $230.00. R
3) Company shall 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 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.

TERMS AND CONDITIONS

Deposits

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 7(1)(a).
2) For customers not meeting the parameters of GENERAL ¶ 2, 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 percent (10%), 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 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.

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to residential customers and to small commercial customers served under Rates CGS. Small business customers with combined gas and electric services must be served exclusively under General Service Rate GS for their electric service. 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 the plan at any time.

The budgeted amount will be determined by Company and will be based on one-twelfth of the 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 the customer’s budget year. If actual usage indicates the customer’s account will not be current with the final payment in the customer’s budget year, the 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

Bill Format

T

a PPL company

Customer Service: 1-800-331-7370 (M-F, 7 a.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: 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
04/24/12	$50.88

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:	3000-1111-2222
Account Name:	JOHN DOE
Service Address:	1234 Main St LOUISVILLE KY
Next Read Will Occur:	05/08/12 - 05/10/12
Date Bill Mailed:	04/11/12 (Meter Read Portion 07)

Averages for Billing Period	This Year	Last Year
Average Temperature	63°	54°
Number of Days Billed	32	29
Gas/ccf per day	1.0	2.2

BILLING SUMMARY

Previous Balance		23.07
Payment(s) Received 03/10 - 4/11		-23.07
Balance as of 4/11		0.00
Current Gas Charges	50.88	
Current Charges as of 11/15		50.88
Total Amount Due		**50.88**

GAS CHARGES

Rate Type: Residential Gas Service

Basic Service Charge	12.50
Gas Distribution Charge ($0.22396 x 35 ccf)	7.84
Gas Supply Component ($0.47423 x 35 ccf)	16.60
Weather Normalization Adjustment ($0.22396 x 58.850 ccf)	13.18
Gas DSM ($0.01709 x 35.00 ccf)	0.60
Home Energy Assistance Fund Charge	0.16
Total Gas Charges	**$50.88**

Meter Reading Information

Meter # 444444	
Actual Reading on 4/10/12	1922
Previous Reading on 3/9/12	1887
Current ccf Usage	**35**
Meter Multiplier	1
Metered ccf Usage	**35**

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

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	04/24/12	$50.88	$53.42	$	$

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

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

PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900062 4#
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40028-8745

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Rev. 11/11

Service Address: 1234 Main St

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TERMS AND CONDITIONS

Bill Format

Account Number 3000-1111-2222 Page 2

T

BILLING INFORMATION	
Late Charge to be Assessed 3 days After Due Date	$2.54

IMPORTANT INFORMATION

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 LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

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.

TERMS AND CONDITIONS

Bill Format

T

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
04/24/12	$122.18

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:	3000-0216-5900-28
Account Name:	JOHN DOE
Service Address:	1234 ANYWHERE ST
Next Read Will Occur:	05/08/12 - 05/10/12
Date Bill Mailed:	04/11/12 (Meter Read Portion 07)

Averages for Billing Period	This Year	Last Year
Average Temperature	63 °	54 °
Number of Days Billed	32	29
Electric/kwh per day	24.3	19.6
Gas/ccf per day	1.0	2.2

BILLING SUMMARY

Previous Balance		102.30
Payment(s) as of 3/10 - 4/11		(102.30)
Balance as of 4/11		0.00
Electric Charges	71.30	
Gas Charges	50.88	
Utility Charges as of 06/20		122.18
Other Charges		
Total Amount Due		122.18

ELECTRIC CHARGES

Rate Type: Residential Electric Service	
Basic Service Charge	8.50
Energy Charge ($0.07242 x 778.00 kwh)	56.34
Electric DSM ($0.00287 x 778 kwh)	2.23
Electric Fuel Adjustment ($0.00472 x 778.00 kwh)	3.67
Environmental Surcharge (0.560% x $70.74)	0.40
Home Energy Assistance Fund Charge	0.16
Total Electric Charges	$71.30

Meter Reading Information	
Meter # 70000	
Actual Reading on 4/10/12	13124
Previous Reading on 3/9/12	12346
Current kwh Usage	778
Meter Multiplier	1
Metered kwh Usage	778

Please see reverse side for additional charges.

Customer Service 1-800-331-7370   PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number	Payment Due Date	Amount Due by Due Date	Amount Due 5 Days After Due Date	Winter Help Donation	Amount Enclosed
3000-0216-5900-28	04/24/12	$122.18	$128.29	$	$

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

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

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Rev. 1111 H

PO BOX 9001960
LOUISVILLE, KY 40290-1960

Service Address: 1234 Main St

#131800082 4#
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40026-8745

020000000000000000000000124560000001189500000000000000

TERMS AND CONDITIONS

Bill Format

T

Account Number 3000-0216-5900-28 Page 2

GAS CHARGES

Rate Type: Residential Gas Service		**Meter Reading Information**	
Basic Service Charge	12.50	Meter # 45678	
Gas Distribution Charge ($0.22396 x 35 ccf)	7.84	Actual Reading on 4/10/12	1922
Gas Supply Component ($0.47423 x 35 ccf)	16.60	Previous Reading on 3/9/12	1887
Weather Normalization Adjustment ($0.22396 x 58.850 ccf)	13.18	**Current ccf Usage**	**35**
Gas DSM ($0.01709 x 35.00 ccf)	0.60	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.16	**Metered ccf Usage**	**35**
Total Gas Charges	**$50.88**		

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date **$6.11**

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 1,556 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 LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

Signature: ______________________________

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 to 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 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 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 the 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

Gas Main Extension Rules

1. Company will extend its gas distribution mains at its own expense for a distance of one hundred (100) feet to each bona-fide applicant who agrees in writing to take service within one (1) year after the extension is completed and who has a suitable Customer's Service Line installed and ready for connection provided the following criteria are met:
   a) The existing main is of sufficient capacity to properly supply the additional customer(s);
   b) The customer(s) contracts to use gas on a continuous basis for one (1) year or more; and,
   c) The potential consumption and revenue will be of such amount and permanence as to warrant the capital expenditures involved to make the investment economically feasible.

2. Company will extend its gas mains in excess of the above distance provided the applicant for service advances to Company an amount equal to the estimated cost of such excess portion of the extension. Company shall have the right to determine the length of the extension and to specify the pipe size and location of the extension, as well as the timing of its construction.

3. Where funds were advanced in accordance with paragraph 2 for extensions into developed residential neighborhoods and notwithstanding paragraph 1, any customer that subsequently connects to the main during a ten-year period from the effective date of the main extension contract shall advance to Company a pro rata share of the cost of the extension over 100 feet per connected customer.

4. For each new year-round customer connected to an extension in accordance with paragraph 3, Company will refund to the previous applicant(s) who advanced funds an amount equal to the difference between the refundable amount advanced and the amount of the advance so determined for the new applicant.

5. Company will extend its gas mains to serve a proposed real estate subdivision provided the applicant for such extension advances to Company an amount equal to the estimated cost of the total extension. Company shall have the right to determine the length of the extension and to specify the pipe size and the location of the extension, as well as the timing of its construction.

6. For each new year-round customer actually connected to the extension within a ten-year period following the effective date of the gas main extension contract, but not to extensions or laterals therefrom, Company will refund to applicant(s) who advanced funds in accordance with paragraph 5 above an amount equal to 100 times the average unit cost per foot of extension advanced by such applicant(s); provided that such refunds shall not exceed, in the aggregate, the amount originally advanced to Company.

7. Company will install at its own expense a service pipe of suitable capacity extending from its gas main to the customer's property line beyond which point all necessary piping shall be installed by and at the expense of the customer and in a manner acceptable to Company.

TERMS AND CONDITIONS

Gas Main Extension Rules

8. Company will install at its own expense the necessary meter together with the regulator required to convert from medium pressure to service pressure. When a high pressure gas line is tapped to serve a customer or group of customers, Company may charge the customer or customers for the estimated installed cost of the tap, any regulation equipment, piping, and any other equipment or facilities determined by Company, in its sole discretion, to be necessary to provide such service consistent with good operating practice.

9. In the event Company is required to make a further extension of its mains to serve a customer, Company reserves the right to tap any extension constructed under these rules and to make connections from such additional extensions without application of the refunds referred to in paragraph 4 or 6 above.

10. The title to all extensions herein provided for, together with all necessary rights-of-way, permits and easements, shall be and remain in Company.

11. Company shall not be obligated to make service connections or to extend its gas mains in cases where such extensions or connections, in the sole judgment of Company would be infeasible, impractical, or contrary to good operating practice, or where such extensions are not in accordance with the terms of the applicable rate schedule.

TERMS AND CONDITIONS

Gas Service Restrictions

By Order dated September 5, 1973, in Case Nos. 5829 and 5839, the Public Service Commission of Kentucky authorized Company to incorporate in its gas tariff restrictions on the supply of gas service, occasioned by the inadequacy of gas supplies to meet customer demands. These restrictions have been modified from time to time by tariff filings authorized or approved by the Commission. Uncertainty as to future gas supply makes it necessary that Company continue to exercise control over the addition of gas loads to its system, as set forth in these rules.

1. **GENERAL**. Except as specifically provided in these rules, Company will not (a) initiate service to any new customer, location, or service point; (b) permit any commercial customer (including any governmental agency or institution) or any industrial customer to increase its connected load or to expand its gas requirements in any manner; or (c) permit any customer to change to another rate schedule for the purpose of obtaining a higher priority under Company's Tariff.

2. **NEW CUSTOMERS**. Until further notice, Company will accept applications for gas service to new customers as set forth below. Main extensions will be made in accordance with the Gas Main Extension Rules contained in this Tariff.

   (a) **FOR SERVICE UNDER RATES RGS, VFD, CGS, DGGS, IGS, and FT**. Single family dwelling units individually metered. Commercial and industrial customers and multi-family residences served through a single meter. Company will have the right to limit the total connected load to a maximum of 8,000 cubic feet per hour, when in Company's judgment such is necessary in order to enable it to continue to supply reliable service to existing customers.

   (b) **FOR SERVICE UNDER OTHER RATE SCHEDULES**. Company may undertake to serve new customers with requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS, IGS, and FT when in its judgment actual and potential gas supplies are sufficient to enable it to do so. Company will designate the applicable rate schedule under which such service will be supplied.

3. **INCREASE IN SERVICE TO EXISTING CUSTOMERS**. Until further notice, Company will, upon application, permit increases in the connected gas load or the gas usage of commercial and industrial customers existing as of the effective date of these rules, as follows:

   (a) **ADDITIONAL SERVICE UNDER RATES RGS, VFD, CGS, DGGS, IGS, and FT.** Company will permit the addition of connected gas loads under Rates RGS, VFD, CGS, DGGS, IGS, and FT. Company will have the right to limit the total connected load to a maximum of 8,000 cubic feet per hour, when in Company's judgment such is necessary in order to enable it to continue to supply reliable service to existing customers.

   (b) **ADDITIONAL SERVICE UNDER OTHER RATE SCHEDULES**. Company may undertake to serve existing customers with additional requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS, IGS, and FT when in its judgment actual and potential gas supplies are sufficient to enable it to do so. Company will designate the applicable rate schedule under which such service will be supplied.

TERMS AND CONDITIONS

Gas Service Restrictions

4. **LOAD ADDITIONS TO BE AGGREGATED**. Limitations on new or additional gas loads as specified herein refer to the aggregate of loads added subsequent to the effective date of these rules, and not to individual increments made from time to time.

5. **VOLUMES OF GAS USAGE**. Daily and monthly volumes of gas usage may be established or increased to reflect additions of connected load or increased usage of connected load existing as of the effective date of these rules. For customers subject to curtailment under Company's Curtailment Rules, Monthly Base Period Volumes will be established or adjusted accordingly.

6. **TRANSFERS BETWEEN LOCATIONS**. Company may permit any customer to transfer his own gas entitlement from one location to another; provided, however, that transfers of service cannot be aggregated so as to exceed the limitations on connected load set forth in Paragraphs 2 and 3 above with respect to Rates RGS, VFD, CGS, DGGS, IGS, and FT.

7. **PRIORITY CONSIDERATIONS**. If at any time, Company is required to select among applicants for service as provided for in Paragraphs 2(b) or 3(b) above, it will, to the extent practicable, observe the following priorities in the order named:

   (a) Schools, hospitals and similar institutions.
   (b) Other commercial establishments.
   (c) Industrial process and feedstock uses.
   (d) Other industrial applications.

8. **LAPSE OF APPLICATIONS**. If any applicant for new or increased service under these rules is not ready to take such service within twelve (12) months from the date of application, such application shall be void. Any reapplication shall be subject to Company's rules in effect at the time thereof.

9. Applicants may make application for gas service beyond that provided for in these rules, to be initiated at such time as these rules may be terminated or modified so as to enable Company to provide the service applied for. Company will file such applications in the order of receipt and dispose of them as circumstances dictate.

TERMS AND CONDITIONS

Curtailment Rules

These rules are established to govern Company's available supply of gas to sales and transportation customers during periods of shortage or substantial reduction in the gas available to Company. These rules are designed to provide for curtailment or discontinuance of service made necessary by a deficiency in gas supply, capacity, or unforeseen emergency circumstances. These rules are designed to enable Company to continue to supply reliable gas service for residential and other human welfare purposes. These rules shall apply and continue in effect until lawfully modified or superseded under the regulatory jurisdiction of the Public Service Commission of Kentucky.

1. **DEFINITIONS** (for purposes of these Rules).

COMMERCIAL CUSTOMERS: Customers engaged primarily in the sale of goods or services, including institutions and local, state and Federal governmental agencies, for uses other than those involving manufacturing as further described in Rate CGS.

HUMAN NEEDS: Residential and other customers whose facilities are used for residential dwellings on either a permanent or temporary basis or a facility providing critical emergency services (including, but not limited to, apartment buildings, correctional institutions, hospitals, nursing homes, assisted living facilities, hotels, motels, fire department stations, police stations, national guard facilities, and emergency response agency facilities).

INDUSTRIAL CUSTOMERS: Customers engaged primarily in a process or processes which create or change raw or unfinished materials into another form or product, including, but not limited to, the generation of electric power as further described in Rate IGS and Rate DGGS.

SMALL INDUSTRIAL CUSTOMER: Any industrial customer whose aggregate of twelve Monthly Base Period Volumes is 10,000 Mcf or less.

LARGE INDUSTRIAL CUSTOMER: Any industrial customer whose aggregate of twelve Monthly Base Period Volumes exceeds 10,000 Mcf.

PILOT LIGHT REQUIREMENTS: Gas used on either a continuous or intermittent basis only for the ignition of the fuel in the main burner; does not include any gas used to preheat or atomize solid or liquid fuels.

BASE PERIOD: The twelve (12) months ending on the October 31 preceding the calendar year which is the subject of the implementation of any curtailments hereunder.

MONTHLY BASE PERIOD VOLUMES: Monthly volumes assigned to each customer determined from its gas consumption (including sales and transportation volumes) during the Base Period. T

AUTHORIZED MONTHLY VOLUME: The volume of gas authorized to be taken during a month and determined by deducting from the Monthly Base Period Volume the curtailment amount applicable for the month. T

TERMS AND CONDITIONS

Curtailment Rules

Some customers may have usage falling within more than one (1) of the above categories; as such, these customers may be required to segregate their total usage accordingly. T T

2. **COMBINATION OF AUTHORIZED MONTHLY VOLUMES**. Subject to a written application by a customer and acceptance thereof by Company, Company may permit any customer served through more than one point of delivery at any location, or any person, corporation or entity served with gas at more than one location, to take gas through the points or at the locations of its choosing, provided that the gas so taken will not exceed the combined Authorized Monthly Volumes applicable to such points of delivery, and provided that only volumes purchased under rate schedules subject to Pro-Rata Curtailment may be so combined. Gas taken through each individual point of delivery will be billed at the rate applicable to such point of delivery.

   The right to combine Authorized Monthly Volumes as herein described is limited to individual customers or individual persons, corporations or entities and such right will not extend to similar combinations between or among unrelated customers. Nor shall such combinations be employed by any customer for the purpose of obtaining a lower overall cost of gas.

   Provided, however, in the case of Industrial Customers provided with sales service under Rate IGS or Special Contracts, which have requested and received approval to combine Authorized Monthly Volumes, Monthly Base Period Volumes for such combined Industrial Customers must aggregate to not less than 10,000 Mcf for a twelve-month period and such combination shall be treated as a Large Industrial Customer for the purpose of implementing either Pro-Rata or Emergency Curtailment.

   For the purpose of assessment of penalties, the point of delivery will be considered on a combined basis, so that the actual combined takes will be measured against combined Authorized Monthly Volumes. It will be the responsibility of any applicant for this treatment to advise Company in writing as to the party or entity to be held accountable for the payment of such penalty.

3. **PRO-RATA CURTAILMENT**. In order to meet seasonal and daily sendout requirements, to preserve underground storage deliverability, and to provide for adequate and timely underground storage injections, Company will implement pro-rata curtailment with respect to the classes of customers here listed:

   (a) All customers served under Rate AAGS.
   (b) Large Industrial Customers provided with sales service under Rate IGS or Special Contracts.

   Company will assign Monthly Base Period Volumes to each customer in the above two classes. Except in the case of an Emergency Curtailment, Company will provide as much notice as practicable to each of these customers that curtailment is being implemented. Such notice will include the percentage curtailment applicable to customer's Monthly Base Period Volume and the Authorized Monthly Volume such customer is authorized to take during said billing period.

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TERMS AND CONDITIONS

Curtailment Rules

Except in the case of Emergency Curtailment, such Pro-Rata Curtailment may only be implemented after Company issues an Operational Flow Order to customers served under Rate FT and takes similar actions applicable to transportation customers served under Special Contracts.

During each month, Pro-Rata Curtailment will be first applied to Rate AAGS customers until such curtailment reaches 100% of Monthly Base Period Volumes (allowing, however, for continuation of Pilot Light Requirements used in connection with alternate fuels). When Rate AAGS customers are 100% curtailed, any additional curtailment required will be apportioned at a uniform percentage to other customers subject to pro-rata curtailment under this Section 3.

4. **EMERGENCY CURTAILMENT**. In the event of an emergency, Company will initiate the following actions, individually or in combination, in the order necessary as time permits so that service may continue to be supplied for residential and other human health, safety and welfare needs.

    (1) Issue Operational Flow Orders to customers served under Rate FT, and take similar actions applicable to transportation customers served under Special Contracts. Customers that fail to comply with Operational Flow Orders will be required to discontinue the use of natural gas.

    (2) Issue Action Alerts to Pool Managers under Rider PS-TS-2 serving customers under Rider TS-2, and take similar actions applicable to transportation customers served under Special Contracts. Customers of Pool Managers that fail to comply with Action Alerts may be required to terminate service under Rider PS-TS-2 and Rider TS-2 and return to firm sales service.

    (3) Discontinue service to customers served under Rate AAGS.

    (4) Implement curtailment of all or a portion of the gas usage by Large Industrial Customers served under either Rate IGS or Special Contracts for gas sales service.

    (5) Once curtailment in level 4 (above) has reached 100% of usage (excluding Pilot Light Requirements), implement curtailment of all or a portion of gas usage to the remaining Small Industrial and non-human needs commercial use customers.

    (6) Company may request that transportation customers served under Rate FT and Special Contracts allow Company's use of customer-owned gas to supply higher priority end-use customers. Company shall negotiate compensation for such gas with any customer that complies with such request.

    (7) Once curtailment of customers in level 5 (above) has reached 100% of usage (excluding Pilot Light Requirements), request reduction of gas usage by human needs commercial, residential, and other human needs customers.

    (8) Implement forced curtailment of gas usage through the isolation of gas distribution load centers from the gas distribution system network.

TERMS AND CONDITIONS

Curtailment Rules

5. **PENALTY CHARGES**. Company may, in its sole discretion, apply a penalty for all gas taken during a period of either Pro-Rata or Emergency Curtailment. T

   Any customer subject to Pro-Rata curtailment in accordance with Section 3 above, who at the end of a month has taken gas in excess of its Authorized Monthly Volumes (excluding Pilot Light Requirements where applicable) for such month, may, in the sole discretion of Company, be subject to a penalty charge applicable to such excess takes of gas at the rate of $15.00 per Mcf plus the highest daily mid-point price posted in "*Platts Gas Daily*" for Dominion-South Point during each month of the period of curtailment, such penalty to be in addition to the established rate for service.

   Any customer subject to Emergency Curtailment in accordance with Section 4 above, who uses quantities of gas in excess of authorized quantities (excluding Pilot Light Requirements where applicable) during a period of such Emergency Curtailment, may, in the sole discretion of Company, be subject to a penalty charge applicable to such unauthorized takes of gas at the rate of $15.00 per Mcf plus the highest daily mid-point price posted in "*Platts Gas Daily*" for Dominion-South Point during each month of the period of curtailment, such penalty to be in addition to the established rate for service. T

   The payment of penalty charges for takes of gas in excess of Authorized Monthly Volumes or authorized quantities shall not be considered as giving any customer the right to make unauthorized takes of gas, nor shall such penalty charges be considered as a substitute for any other remedy available to Company.

   Company shall return to all customers through Company's Gas Supply Clause any penalty charges collected from customers under this Section 5 net of any penalty charges incurred from Company's supplier(s).

6. **DISCONTINUANCE OF SERVICE.** If any customer subject to curtailment under these rules fails to limit its use of gas as provided for herein, then Company shall have the right to immediately discontinue all gas supply to such customer.

Special Contracts

Summary of Proposed Charges Under Gas Special Contracts

Customer 1	Customer Charge:	$275.00 per month
	Administrative Charge	$600.00 per month
	Distribution Charge	$0.1049 per Mcf
	Demand Charge	$2.75 per Mcf
	Daily Storage Charge	$0.1833 per Mcf
Customer 2	Sales Rate:	
	Customer Charge:	$175.00 per month
	Monthly Demand Charge:	$10.90 per Mcf
	Distribution Charge :	$0.3222 per Mcf Delivered
	Gas Supply Cost Component:	Per Rate IGS
	Transportation Rate:	
	Customer Charge:	$781.00 per month
	Demand Charge	$2.43 per Mcf
	Distribution Charge	$0.0487 per Mcf Delivered
	Daily Storage Charge	$0.1833 per Mcf

Louisville Gas and Electric Company
Case No. 2012-00222
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. Electric No. 8
Canceling P.S.C. Electric No. 7

Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

In the nine counties of the Louisville, Kentucky, metropolitan area
as depicted on territorial maps as filed with the

PUBLIC SERVICE COMMISSION

OF KENTUCKY

Date of Issue	Date Effective
August 6, 2010	August 1, 2010

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

P.S.C. Electric No. 9
Canceling P.S.C. Electric No.8

Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

In the nine counties of the Louisville, Kentucky, metropolitan area
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

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Fifth Revision of Original Sheet No. 1
Canceling P.S.C. Electric No. 8, 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
PS	Power Service	15	02-29-12
ITODS	Industrial Time-of-Day Secondary Service	20	02-29-12
CTODS	Commercial Time-of-Day Secondary Service	21	02-29-12
ITODP	Industrial Time-of-Day Primary Service	22	02-29-12
CTODP	Commercial Time-of-Day Primary Service	23	02-29-12
RTS	Retail Transmission Service	25	02-29-12
FLS	Fluctuating Load Service	30	02-29-12
LS	Lighting Service	35	02-29-12
RLS	Restricted Lighting Service	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	11-01-95
NMS	Net Metering Service	57	08-17-09
EF	Excess Facilities	60	08-01-10
RC	Redundant Capacity	61	08-01-10
SS	Supplemental/Standby Service Rider	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	02-06-09
GER	Green Energy Riders	70	06-01-10
EDR	Economic Development Rider	71	08-11-11
RTP	Real Time Pricing	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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00010 dated March 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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	
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	11-01-95	
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/Standby Service Rider	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	08-01-12	T
GER	Green Energy Riders	70	06-01-10	
EDR	Economic Development Rider	71	08-11-11	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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Fourteenth Revision of Original Sheet No. 1.1
Canceling P.S.C. Electric No. 8, Thirteenth Revision of Original Sheet No. 1.1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

	Title	Sheet Number	Effective Date
SECTION 3 – Pilot Programs			
LEV	Low Emission Vehicle Service	79	02-29-12
SECTION 4 – Adjustment Clauses			
FAC	Fuel Adjustment Clause	85	06-29-11
DSM	Demand-Side Management Cost Recovery Mechanism	86	05-31-12
ECR	Environmental Cost Recovery Surcharge	87	12-16-11
FF	Franchise Fee Rider	90	10-16-03
ST	School Tax	91	08-01-10
HEA	Home Energy Assistance Program	92	01-01-12
SECTION 5 – Terms and Conditions			
	Customer Bill of Rights	95	08-01-10
	General	96	02-06-09
	Customer Responsibilities	97	08-01-10
	Company Responsibilities	98	02-06-09
	Character of Service	99	08-01-10
	Specific Terms and Conditions Applicable to Rate RS	100	02-06-09
	Billing	101	08-01-10
	Deposits	102	08-01-10
	Budget Payment Plan	103	08-01-10
	Bill Format	104	12-22-11
	Discontinuance of Service	105	08-01-10
	Line Extension Plan	106	12-30-11
	Energy Curtailment and Restoration Procedures	107	08-01-10

Date of Issue: April 30, 2012
Date Effective: May 31, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 1.1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

	Title	Sheet Number	Effective Date	
SECTION 3 – Pilot Programs				
LEV	Low Emission Vehicle Service	79	08-01-12	T
SECTION 4 – Adjustment Clauses				
FAC	Fuel Adjustment Clause	85	06-29-11	
DSM	Demand-Side Management Cost Recovery Mechanism	86	04-01-12	
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HEA	Home Energy Assistance Program	92	01-01-12	
SECTION 5 – Terms and Conditions				
	Customer Bill of Rights	95	08-01-10	
	General	96	02-06-09	
	Customer Responsibilities	97	08-01-12	T
	Company Responsibilities	98	08-01-12	T
	Character of Service	99	08-01-10	
	Specific Terms and Conditions Applicable to Rate RS	100	02-06-09	
	Billing	101	08-01-12	T
	Deposits	102	08-01-12	T
	Budget Payment Plan	103	08-01-10	
	Bill Format	104	08-01-12	T
	Discontinuance of Service	105	08-01-10	
	Line Extension Plan	106	12-30-11	
	Energy Curtailment and Restoration Procedures	107	08-01-10	

Date of Issue: June 29, 2012
Date Effective: April 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 5
Canceling P.S.C. Electric No. 8, 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.

RATE

Basic Service Charge:	$8.50 per month
Plus an Energy Charge of:	$0.07242 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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.

RATE

Basic Service Charge:	$13.00 per month	I
Plus an Energy Charge of:	$ 0.07513 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

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

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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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 7
Canceling P.S.C. Electric No. 8, 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:	$0.07242 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

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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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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	I
Plus an Energy Charge of:	$ 0.07513 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
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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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 10
Canceling P.S.C. Electric No. 8, 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. Electric No. 6, 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:	$ 0.08240 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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. Electric No. 6, 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 T T T T T 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:	$ 0.08624 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. 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, Louisville, Kentucky

The proposed LG&E General Service Rate GS is contained on two pages instead of the current one page.

Standard Rate

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.

Louisville Gas and Electric Company

P. S.C. Electric No. 8, Second Revision of Original Sheet No. 15
Canceling P.S.C. Electric No. 8, First Revision of Original Sheet No. 15

Standard Rate PS
Power Service Rate

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 P.S.C. of Ky. Electric No. 6, Fourth Revision of Original Sheet No. 15, Large Commercial Rate LC, and Fourth Revision of Original Sheet No. 25, Large Power Industrial Rate LP, 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:	$ 0.03421	$ 0.03421
Plus a Demand Charge per kW of:		
Summer Rate: (Five Billing Periods of May through September)	$15.39	$13.55
Winter Rate: (All other months)	$13.14	$11.31

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 load expected on the system or 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
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Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 15

Standard Rate PS
Power Service Rate

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 P.S.C. of Ky. T
Electric No. 6, Fourth Revision of Original Sheet No. 15, Large Commercial Rate LC, and Fourth Revision of Original Sheet No. 25, Large Power Industrial Rate LP, as of February 6, 2009, with loads not meeting these criteria will continue to be served under this rate at their option. If T
Customer is taking service under this rate schedule and subsequently elects to take service under T
another rate schedule, Customer may not again take service under this rate schedule unless and T
until Customer 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:	$ 0.03615	$ 0.03416	I
Plus a Demand Charge per kW of:			
Summer Rate: (Five Billing Periods of May through September)	$16.20	$ 13.54	I
Winter Rate: (All other months)	$13.75	$ 11.31	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 load expected on the system or 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, Louisville, Kentucky

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 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.

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 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.

Louisville Gas and Electric Company

Standard Rate — ITODS

Industrial Time-of-Day Secondary Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is available for secondary industrial service. Service under this schedule will be limited to minimum average loads of 250 kW 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:	$300.00
Plus an Energy Charge per kWh of:	$ 0.02984
Plus a Maximum Load Charge per kW of:	
Peak Demand Period	$ 5.18
Intermediate Demand Period	$ 3.68
Base Demand Period	$ 5.46

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

The current LG&E Industrial Time-of-Day Secondary Service Rate ITODS is proposed to be combined with the current Commercial Time-of Day Secondary Service Rate CTODS. The new combined rate will be named Time-of-Day Secondary Service Rate TODS.

Standard Rate ITODS

Industrial 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, 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)

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

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

The current LG&E Industrial Time-of-Day Secondary Service Rate ITODS is proposed to be combined with the current Commercial Time-of Day Secondary Service Rate CTODS. The new combined rate will be named Time-of-Day Secondary Service Rate TODS.

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 21
Canceling P.S.C. Electric No. 8, First Revision of Original Sheet No. 21

Standard Rate — CTODS

Commercial Time-of-Day Secondary Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for secondary commercial service. Service under this schedule will be limited to minimum average loads of 250 kW 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:	$ 0.03383
Plus a Maximum Load Charge per kW of:	
Peak Demand Period	$ 5.78
Intermediate Demand Period	$ 4.25
Base Demand Period	$ 3.76

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

The current LG&E Commercial Time-of-Day Secondary Service Rate CTODS is proposed to be combined with Industrial Time-of Day Secondary Service Rate ITODS. The new combined rate will be named Time-of-Day Secondary Service Rate TODS.

Louisville Gas and Electric Company

Standard Rate CTODS

Commercial 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, 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)

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

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

The current LG&E Commercial Time-of-Day Secondary Service Rate CTODS is proposed to be combined with Industrial Time-of Day Secondary Service Rate ITODS. The new combined rate will be named Time-of-Day Secondary Service Rate TODS.

Proposed Time-of-Day Secondary Service Rate TODS is a combination of the current Industrial Time-of-Day Secondary Service Rate ITODS and the current Commercial Time-of-Day Secondary Service Rate CTODS, and is not currently available.

Standard Rate

TODS
Time-of-Day Secondary Service

N

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.

RATE

Basic Service Charge per month:	$200.00
Plus an Energy Charge per kWh of:	$ 0.03580
Plus a Maximum Load Charge per kW of:	
Peak Demand Period	$ 6.15
Intermediate Demand Period	$ 4.52
Base Demand Period	$ 4.00

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, Louisville, Kentucky

Proposed Time-of-Day Secondary Service Rate TODS is a combination of the current Industrial Time-of-Day Secondary Service Rate ITODS and the current Commercial Time-of-Day Secondary Service Rate CTODS, and is not currently available.

N

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, 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)

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

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: 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, Louisville, Kentucky

Louisville Gas and Electric Company

Standard Rate ITODP

Industrial Time-of-Day Primary Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for primary industrial service. Service under this schedule will be limited to minimum average loads of 250 kW and maximum new loads not exceeding 50,000 kW. Existing customers may increase loads to a maximum of 75,000 kW by up to 2,000 kW 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 to 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:	$ 0.02984
Plus a Demand Charge per kW of:	
Basic Demand	$ 4.17
Peak Demand	
Summer Peak Period	$ 10.12
Winter Peak Period	$ 7.32

Basic Demand Charges are applicable to the highest average load in kilowatts recorded during any 15-minute interval of the billing period and Peak Demand Charges are applicable to the highest average load in kilowatts recorded during any 15-minute interval of the peak period, as defined herein, in the monthly billing period, but not less than 50% of the maximum demands similarly determined for any of the four (4) billing periods of June through September within the eleven (11) preceding months.

SUMMER PEAK PERIOD is defined as weekdays from 10 A.M. to 9 P.M, Eastern Standard Time, during the four (4) billing periods of June through September.

WINTER PEAK PERIOD is defined as weekdays from 8 A.M. to 10 P.M., Eastern Standard Time, during the eight (8) billing periods of October through May.

POWER FACTOR PROVISION
The monthly demand charge shall be decreased .4% for each whole one percent by which the monthly average power factor exceeds 80% lagging and shall be increased .6% for each whole one percent by which the monthly average power factor is less than 80% lagging.

Monthly average power factor shall be determined by means of a reactive component meter ratcheted to record only lagging reactive kilovolt ampere hours, used in conjunction with a standard watt-hour meter.

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

The current LG&E Industrial Time-of-Day Primary Service Rate ITODP is proposed to be combined with the current Commercial Time-of Day Primary Service Rate CTODP. The new combined rate will be named Time-of-Day Primary Service Rate TODP.

Louisville Gas and Electric Company

Standard Rate	ITODP
	Industrial Time-of-Day Primary 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
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

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

The current LG&E Industrial Time-of-Day Primary Service Rate ITODP is proposed to be combined with the current Commercial Time-of Day Primary Service Rate CTODP. The new combined rate will be named Time-of-Day Primary Service Rate TODP.

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 23
Canceling P.S.C. Electric No. 8, First Revision of Original Sheet No. 23

Standard Rate	CTODP
	Commercial Time-of-Day Primary Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for primary commercial 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 to the appropriate rate or have a rate developed based on their electrical characteristics.

RATE

Basic Service Charge per month:	$200.00
Plus an Energy Charge per kWh of:	$ 0.03383
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 5.65
Intermediate Demand Period	$ 4.15
Base Demand Period	$ 2.59

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
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Date of Issue: February 17, 2012
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Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

The current LG&E Commercial Time-of-Day Primary Service Rate CTODP is proposed to be combined with the current Industrial Time-of Day Primary Service Rate ITODP. The new combined rate will be named Time-of-Day Primary Service Rate TODP.

Louisville Gas and Electric Company

Standard Rate CTODP

Commercial 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 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

The current LG&E Commercial Time-of-Day Primary Service Rate CTODP is proposed to be combined with the current Industrial Time-of Day Primary Service Rate ITODP. The new combined rate will be named Time-of-Day Primary Service Rate TODP.

Proposed Time-of-Day Primary Service Rate TODP is a combination of the current Industrial Time-of-Day Primary Service Rate ITODP and the current Commercial Time-of-Day Primary Service Rate CTODP, and is not currently available.

Standard Rate | TODP | N
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 maximum of 75,000 kVA by up to 2,000kVA per year or in greater increments with approval of Company's transmission operator.

RATE

Basic Service Charge per month:	$300.00
Plus an Energy Charge per kWh of:	$ 0.03028
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 5.59
Intermediate Demand Period	$ 3.95
Base Demand Period	$ 3.72

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, Louisville, Kentucky

Proposed Time-of-Day Primary Service Rate TODP is a combination of the current Industrial Time-of-Day Primary Service Rate ITODP and the current Commercial Time-of-Day Primary Service Rate CTODP, and is not currently available.

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 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, 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 25
Canceling P.S.C. Electric No. 8, 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:	$ 0.02984
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 4.32
Intermediate Demand Period	$ 2.82
Base Demand Period	$ 2.57

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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. T
Existing customers may increase loads to a 12-month-average monthly maximum of 75,000 T
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:	$ 0.03228	I
Plus a Maximum Load Charge per kVA of:		
Peak Demand Period	$ 4.64	I
Intermediate Demand Period	$ 3.03	I
Base Demand Period	$ 2.76	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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 30
Canceling P.S.C. Electric No. 8, 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 FLS schedule of Kentucky Utilities 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:	$ 0.03710	$ 0.03428
Plus a Maximum Load Charge per kVA of:		
Peak Demand Period	$ 2.71	$ 2.71
Intermediate Demand Period	$ 1.71	$ 1.71
Base Demand Period	$ 1.71	$ 0.96

Where:
the monthly 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 60% 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.

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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 FLS schedule of Kentucky Utilities 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:	$ 0.03228	$ 0.03228	I
Plus a Maximum Load Charge per kVA of:			
Peak Demand Period	$ 3.03	$ 3.03	I
Intermediate Demand Period	$ 1.92	$ 1.92	I
Base Demand Period	$ 1.90	$ 1.15	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 T

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.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 30.1

Standard Rate FLS
Fluctuating Load Service

ADJUSTMENT CLAUSES
The 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.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 30.1

Standard Rate FLS
Fluctuating Load Service

ADJUSTMENT CLAUSES
The 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.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, First Revision of Original Sheet No. 30.2
P.S.C. Electric No. 8, Original Sheet No. 30.2

Standard Rate — FLS
Fluctuating Load Service

TERM OF CONTRACT

Unless terminated by mutual agreement, the initial term of contract for service shall be for a fixed term of five (5) years with successive one (1) 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 csr30. 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 with ECAR or an ISO/TRO. LKE System, as used

Date of Issue: November 2, 2010
Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case Nos. 2009-00549 dated July 30, 2010 and 2010-00204 dated September 30, 2010.

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 30.2

Standard Rate — FLS
Fluctuating Load Service

TERM OF CONTRACT

Unless terminated by mutual agreement, the initial term of contract for service shall be for a fixed term of five (5) years with successive one (1) 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 T 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 CSR30. 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 LG&E 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, First Revision of Original Sheet No. 30.3
P.S.C. Electric No. 8, Original Sheet No. 30.3

Standard Rate — FLS

Fluctuating Load Service

herein, shall consist of LG&E and KU. 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case Nos. 2009-00549 dated July 30, 2010 and 2010-00204 dated September 30, 2010.

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 30.3

Standard Rate — FLS

Fluctuating Load Service

and KU. 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 35
Canceling P.S.C. Electric No. 8, First Revision of Original Sheet No. 35

Standard Rate | LS
Lighting Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
To any customer who can be served in accordance with the special terms and conditions set forth herein and who is willing to contract for service in accordance with such special terms and conditions.

CHARACTER OF SERVICE
This rate schedule covers electric lighting service to outdoor equipment 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. Service under this rate will be available on an automatically controlled dusk-to-dawn every-night schedule of approximately 4000 hours per year, and only to the types of lighting units specified herein.

RATES
UNDERGROUND SERVICE
Based on lighting choice, Company will furnish and install the lighting unit complete with lamp, fixture, photoelectric control, mast arm (cobra head) and pole.

Type Of Fixture	Approx. Lumens	kW Rating	Monthly Charge
High Pressure Sodium			
4 Sided Colonial	5,800	0.083	$18.76
4 Sided Colonial	9,500	0.117	19.36
4 Sided Colonial	16,000	0.181	20.36
Acorn	5,800	0.083	19.13
Acorn	9,500	0.117	21.36
Acorn (Bronze Pole)	9,500	0.117	22.44
Acorn	16,000	0.181	22.27
Acorn (Bronze Pole)	16,000	0.181	23.28
Contemporary	16,000	0.181	28.35
Fixture Only	16,000	0.181	15.38
Contemporary	28,500*	0.294	31.00
Fixture Only	28,500*	0.294	16.92
Contemporary	50,000*	0.471	36.04
Fixture Only	50,000*	0.471	20.52
Cobra Head	16,000*	0.181	24.93
Cobra Head	28,500*	0.294	26.74
Cobra Head	50,000*	0.471	31.83

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 35

Standard Rate | LS
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. T

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	
					T
High Pressure Sodium					T
452	Cobra Head	16,000	0.181	$12.48	N
453	Cobra Head	28,500	0.294	14.57	N
454	Cobra Head	50,000*	0.471	16.58	N
455	Directional	16,000	0.181	$13.44	N
456	Directional	50,000*	0.471	17.41	N
457	Open Bottom	9,500	0.117	$10.60	N
Metal Halide					T
470	Directional	12,000	0.150	$12.47	T/I
473	Directional	32,000	0.350	18.09	T/I
476	Directional	107,800*	1.080	37.80	T/I

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. T T T T

Date of Issue: June 29, 2012
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Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 35.1
Canceling P.S.C. Electric No. 8, First Revision of Original Sheet No. 35.1

Standard Rate LS

Lighting Service

UNDERGROUND SERVICE (Continued)

Type Of Fixture	Approx. Lumens	kW Rating	Monthly Charge
High Pressure Sodium			
* London (10' Smooth Pole)	5,800	0.083	$31.73
* London (10' Fluted Pole)	5,800	0.083	33.64
* London (10' Smooth Pole)	9,500	0.117	32.50
* London (10' Fluted Pole)	9,500	0.117	34.41
* Victorian (10' Smooth Pole)	5,800	0.083	30.80
* Victorian (10' Fluted Pole)	5,800	0.083	31.45
* Victorian (10' Smooth Pole)	9,500	0.117	32.73
* Victorian (10' Fluted Pole)	9,500	0.117	33.37
* Bases Available:			
Old Town / Manchester			$ 2.83
Chesapeake / Franklin			2.83
Jefferson / Westchester			2.83
Norfolk / Essex			3.00

Mercury Vapor

Mercury Vapor is 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.

Type Of Fixture	Approx. Lumens	kW Rating	Monthly Charge
4 Sided Colonial	4,000	0.124	$16.35
4 Sided Colonial	8,000	0.210	18.02
Cobra Head	8,000	0.210	21.99
Cobra Head	13,000	0.298	23.46
Cobra Head	25,000	0.462	26.91

The above rates for UNDERGROUND SERVICE contemplate a normal installation served from underground lines located in the streets, with a direct buried cable connection of not more than 200 feet per unit in those localities supplied with electric service through underground distribution facilities. If additional facilities are required, the customer shall make non-refundable cash advance equivalent to the installed cost of such excess facilities. The Company may provide underground lighting service in localities otherwise served through overhead facilities when, in its judgment, it is practicable to do so from an operating and economic standpoint. Company may decline to install equipment and provide service thereto in locations deemed by the Company as unsuitable for underground installation.

CUSTOM 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.

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, Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 35.1

Standard Rate LS

Lighting Service

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. For poles installed prior to 8/1/2010, such charge for each pole and span of secondary installed after 6/30/2004 and used in providing a light offered under LS as listed under RLS Sheet No. 36, Bill Code 958, and such charge for each pole and span of secondary installed prior to 6/30/2004 and used in providing a light offered under LS as listed under RLS Sheet No. 36, Bill Code 900. T

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. T T T T

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Fixture Only	Decorative Smooth	Historic Fluted	
High Pressure Sodium							T
412	Colonial, 4-Sided	5,800	0.083		$19.74		T/I
413	Colonial, 4-Sided	9,500	0.117		20.37		T/I
415	Acorn	5,800	0.083		$20.13		T/I
416	Acorn	9,500	0.117		22.48		T/I
427	London	5,800	0.083			$35.40	T/I
429	London	9,500	0.117			36.21	T/I
431	Victorian	5,800	0.083			$33.10	T/I
433	Victorian	9,500	0.117			35.12	T/I
						Westchester/Norfolk	T
956	Victorian/London Bases					$ 3.61	N
423	Cobra Head	16,000	0.181		$26.23		T/I
424	Cobra Head	28,500	0.294		28.14		T/I
425	Cobra Head	50,000*	0.471		33.50		T/I
439/420	Contemporary	16,000	0.181	$16.18	$29.83		T/I
440/421	Contemporary	28,500*	0.294	17.81	32.62		T/I
441/422	Contemporary	50,000*	0.471	21.59	37.93		T/I
400	Dark Sky	4,000	0.060		$23.82		T/I
401	Dark Sky	9,500	0.117		24.86		T/I
Metal Halide							T
479/480	Contemporary	12,000	0.150	$13.76	$23.69		T/I
481/482	Contemporary	32,000	0.350	19.90	29.81		T/I
483/484	Contemporary	107,800*	1.080	40.81	50.71		T/I

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Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 35.2
Canceling P.S.C. Electric No. 8, First Revision of Original Sheet No. 35.2

Standard Rate LS
Lighting Service

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	16,000	0.181	$11.62
Cobra Head	28,500*	0.294	13.44
Cobra Head	50,000*	0.471	18.53
Directional Flood	16,000	0.181	13.23
Directional Flood	50,000*	0.471	19.50
Open Bottom	9,500	0.117	10.40

Mercury Vapor

Mercury Vapor is 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.

Type Of Fixture	Approx. Lumens	kW Rating	Monthly Charge
Cobra Head	8,000	0.210	$10.26
Cobra Head	13,000	0.298	11.74
Cobra Head	25,000	0.462	15.18
Directional Flood	25,000	0.462	16.53
Open Bottom	8,000	0.210	10.00

ADDITIONAL FACILITIES

The above rates for OVERHEAD SERVICE contemplate installation on an existing wood pole and, if needed, up to 150 feet of conductor. If the location of an existing pole is not suitable for the installation of a lighting unit, the Company will extend its secondary conductor one span and install one additional pole for the support of such unit, the customer will pay an additional charge. Such charge of $10.92 per month for each such wood pole installed applies to lighting installed prior to March 1, 2010. Thereafter, the Company may furnish any additional 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.

NOTE: *NOT AVAILABLE FOR URBAN RESIDENTIAL HOME USE

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 35.2

Standard Rate LS
Lighting 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 conventional overhead lighting system. T

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.

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Louisville Gas and Electric Company

P. S. C. Electric No. 8, Second Revision of Original Sheet No. 35.3
Canceling P.S.C. Electric No. 8, First Revision of Original Sheet No. 35.3

Standard Rate LS
Lighting Service

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	$11.85
Directional Fixture With Wood Pole	12,000	0.150	$14.05
Directional Fixture With Direct Burial Metal Pole	12,000	0.150	$21.26
Directional Fixture Only	32,000	0.350	$17.19
Directional Fixture With Wood Pole	32,000	0.350	$19.40
Directional Fixture With Metal Pole	32,000	0.350	$26.60
Directional Fixture Only	107,800	1.080	$35.92
Directional Fixture With Wood Pole	107,800	1.080	$38.99
Directional Fixture With Metal Pole	107,800	1.080	$45.32
Contemporary Fixture Only	12,000	0.150	$13.08
Contemporary Fixture With Direct Burial Metal Pole	12,000	0.150	$22.51
Contemporary Fixture Only	32,000	0.350	$18.91
Contemporary Fixture With Metal Pole	32,000	0.350	$28.33
Contemporary Fixture Only	107,800	1.080	$38.78
Contemporary Fixture With Metal Pole	107,800	1.080	$48.19

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

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 35.3

Standard Rate LS
Lighting Service

TERMS AND CONDITIONS (continued) T

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.

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Standard Rate LS

Lighting Service

SPECIAL TERMS AND CONDITIONS

1. All lighting units, poles and conductors installed in accordance herewith shall be the property of Company, and Company shall have access to the same for maintenance, inspection and all other proper purposes. Company shall have the right to make other attachments to the poles and to further extend the conductors installed in accordance herewith when necessary for the further extension of its electric service.

2. 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 the customer to obtain such permit.

3. All servicing and maintenance will be performed only during regular schedule 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

4. The customer will exercise proper care to protect the property of Company on his premises, and in the event of loss or damage to Company's property arising from the negligence of the customer, the cost of the necessary repair or replacement shall be paid by the customer. Company may decline to install equipment and provide service thereto in locations where, in Company's judgment, such equipment will be subject to unusual hazards or risk of damage.

5. 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 set forth in its General Rules and Regulations. Upon permanent discontinuance of service, lighting units and other equipment will be removed.

6. Before agreeing to install lighting units Company may require reasonable assurance that the interest of the applicant for service will continue for 5 years or that the service will be continued by another party after the interest of the original applicant has terminated.

7. If lighting unit(s) are removed prior to the 5 year term, customer agrees to pay the Company a lump sum equal to the monthly lease times the number of months remaining needed to equal 60 months (5 years).

TERMS AND CONDITIONS

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

The proposed LG&E Lighting Service Rate LS is contained on four pages instead of the current five pages.

Louisville Gas and Electric Company

P.S. C. Electric No. 8, Second Revision of Original Sheet No. 36
Canceling P.S.C. Electric No. 8, First Revision of Original Sheet No. 36

Standard Rate RLS
Restricted Lighting Service

OUTDOOR LIGHTING

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE - RESTRICTED
To any customer who can be served in accordance with the special terms and conditions set forth herein and who is willing to contract for service in accordance with such special terms and conditions. This rate schedule will continue to be available to fixtures that were being served hereunder on July 1, 2004, and will not be available for the addition of new fixtures.

CHARACTER OF SERVICE
These rates cover electric lighting service to outdoor equipment 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. Service under this rate will be available on an automatically controlled dusk-to-dawn every-night schedule of approximately 4000 hours per year, and only to the types of lighting units specified herein.

RATES

Type of Unit	Rate Per Month Per Unit	
Overhead Service	Installed Prior to	Installed After
Mercury Vapor	January 1, 1991	December 31, 1990
100 Watt	$7.92	N/A
175 Watt	8.97	$ 10.37
250 Watt	10.33	11.80
400 Watt	12.78	14.39
1000 Watt	24.04	26.68
1000 Watt Flood	24.04	26.81
High Pressure Sodium Vapor		
100 Watt	$10.00	$10.00
150 Watt	12.63	12.63
250 Watt	14.97	14.97
400 Watt	16.34	16.34
1000 Watt	N/A	38.35
Underground Service		
Mercury Vapor		
100 Watt - Top Mounted	$13.16	$13.15
175 Watt - Top Mounted	14.06	15.03
400 Watt - Top Mounted	16.22	16.22
High Pressure Sodium Vapor		
70 Watt - Top Mounted	$13.30	$13.30
100 Watt - Top Mounted	17.49	17.68
150 Watt - Top Mounted	N/A	21.08
150 Watt	23.52	23.52
250 Watt	27.14	27.14
400 Watt	30.31	30.31
1000 Watt	N/A	68.13

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 36

Standard Rate RLS
Restricted Lighting Service

APPLICABLE T
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 composing 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. T

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).

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Fixture Only	Fixture & Wood Pole	Fixture & Orn. Pole	
Mercury Vapor							T
252	Cobra/Open Bottom	8,000	0.210	$ 9.20			N
458	Cobra Head	8,000	0.210	$10.80			T/I
203	Cobra Head	13,000	0.298	10.45			N
204	Cobra Head	25,000	0.462	12.71			N
209	Cobra Head	60,000	1.180	25.70			N
207	Directional	25,000	0.462	$14.78			N
210	Directional	60,000	1.180	26.92			N
201	Open Bottom	4,000	0.100	$ 7.94			N
Metal Halide							T
471	Directional	12,000	0.150		$14.79	N/A	T/I
474/475	Directional	32,000	0.350		20.42	27.99	T/I
477	Directional	107,800	1.080		41.03	N/A	T/I
Wood Pole							T
958	Installed Before 3/1/2010			$11.49			T/I
900	Installed Before 7/1/2004			2.09			T/I

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P.S.C. Electric No. 8, Second Revision of Original Sheet No. 36.1
Canceling P.S.C. Electric No. 8, First Revision of Original Sheet No. 36.1

Standard Rate — RLS

Restricted Lighting Service (Continued)

Decorative Lighting Service	Rate Per Month Per Unit
Fixtures	
Acorn with Decorative Basket	
70 Watt High Pressure Sodium	$18.45
100 Watt High Pressure Sodium	19.48
8-Sided Coach	
70 Watt High Pressure Sodium	18.63
100 Watt High Pressure Sodium	19.68
Poles	
10' Smooth	10.44
10' Fluted	12.46
Bases	
Old Town / Manchester	3.35
Chesapeake / Franklin	3.60
Jefferson / Westchester	3.62
Norfolk / Essex	3.81

NA – Not Available

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 Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

SPECIAL TERMS AND CONDITIONS

1. Company will furnish and install the lighting unit complete with lamp, fixture or luminaire, control device, and mast arm. The above rates for overhead service contemplate installation on an existing wood pole with service supplied from overhead circuits only; provided, however, that, when possible, floodlights served hereunder may be attached to existing metal street lighting standards supplied from overhead service. If the location of an existing pole is not suitable for the installation of a lighting unit, the Company will extend its secondary conductor one span and install an additional pole for the support of such unit, the customer to pay an additional charge of $1.99 per month for each such pole so installed. If still further poles or conductors are required to extend service to the lighting unit, the customer will be required to make a non-refundable cash advance equal to the installed cost of such further facilities.

2. The above rates for underground service contemplate a normal installation served from underground lines located in the streets, with a direct buried cable connection of not more than 200 feet per unit in those localities supplied with electric service through underground distribution facilities. If additional facilities are required, the customer shall make

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Date Effective: With Bills Rendered On and After February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 36.1

Standard Rate — RLS

Restricted Lighting Service

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. T T T T

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Fixture Only	Monthly Charge: Decorative Smooth	
High Pressure Sodium						T
275	Cobra/Contemporary	16,000	0.181		$24.74	N
266	Cobra/Contemporary	28,500	0.294		27.03	N
267	Cobra Contemporary	50,000	0.471		30.83	N
276	Coach/Acorn	5,800	0.083		$14.01	N
274	Coach/Acorn	9,500	0.1117		17.00	N
277	Coach/Acorn	16,000	0.181		21.97	N
279/278	Contemporary	120,000	1.000	$39.51	$71.15	N
417	Acorn, Bronze	9,500	0.117		$23.61	T/I
419	Acorn, Bronze	16,000	0.180		24.50	T/I
280	Victorian	5,800	0.083	$19.30		N
281	Victorian	9,500	0.117	20.22		N
282	London	5,800	0.083	$19.46		N
283	London	9,500	0.117	20.69		N
426	London	5,800	0.083		$33.39	T/I
428	London	9,500	0.117		34.20	T/I
430	Victorian	5,800	0.083		32.41	T/I
432	Victorian	9,500	0.117		34.44	T/I
Victorian/London Bases						T
950	Old Town				$ 3.52	N
951	Chesapeake				3.80	N
Poles						T
901	10" Smooth Pole				10.99	N
902	10" Fluted Pole				13.11	N

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, Louisville, Kentucky

a non-refundable cash advance equivalent to the installed cost of such excess facilities. The Company may provide underground lighting service in localities otherwise served through overhead facilities when, in its hereto in locations deemed by the Company as unsuitable for underground installation.

3. DECORATIVE LIGHTING SERVICE. The monthly rates for Decorative Lighting are calculated as the sum of the rates for the individual elements of the customized light. For example, the monthly rate will be calculated as the sum of the rates for the chosen fixture style and wattage, the chosen pole style, and the chosen base style, if one is chosen. This provides flexibility for the Company to meet the individual desires of each Decorative Lighting customer.

4. All lighting units, poles and conductors installed in accordance herewith shall be the property of Company, and Company shall have access to the same for maintenance, inspection and all other proper purposes. Company shall have the right to make other attachments to the poles and to further extend the conductors installed in accordance herewith 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 the customer to obtain such permit.

6. All servicing and maintenance will be performed only during regular schedule 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.

7. The customer will exercise proper care to protect the property of Company on his premises, and in the event of loss or damage to Company's property arising from the negligence of the customer, the cost of the necessary repair or replacement shall be paid by the customer. Company may decline to install equipment and provide service thereto 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 two 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 set forth in its General Rules and Regulations. Upon permanent discontinuance of service, lighting units and other equipment will be removed.

9. Before agreeing to install lighting units Company may require reasonable assurance that the interest of the applicant for service will continue for a minimum fixed contract term or that the service will be continued by another party after the interest of the original applicant has terminated.

10. Mercury Vapor is 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.

UNDERGROUND SERVICE (continued) T

RATE Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth	
						T T T T
Mercury Vapor						T
318	Cobra Head	8,000	0.210		$17.18	N
314	Cobra Head	13,000	0.298		18.82	N
315	Cobra Head	25,000	0.462		22.31	N
347	Cobra (State of KY Pole)	25,000	0.462	$22.30		T/I
206	Coach	4,000	0.100		$12.33	N
208	Coach	8,000	0.210		13.95	N
Incandescent						T
349	Continental Jr.	1,500	0.102		$ 8.86	T/I
348	Continental Jr.	6,000	0.447		12.38	T/I

Where Customer's location required the installation of additional facilities, Company may have furnished the requested facilities at an additional charge per month to be determined under the Excess Facilities Rider. T

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

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 36.3
Canceling P.S.C. Electric No. 8, First Revision of Original Sheet No. 36.3

Standard Rate RLS
Restricted Lighting Service

PUBLIC STREET LIGHTING

AVAILABILITY OF SERVICE - RESTRICTED
The following lighting units and rates are available to municipal, county, state and Federal governments, including divisions thereof, and other bodies politic which have the authority to levy and collect general taxes, for the lighting of public streets and roads, public parks and other outdoor locations open to and reserved for general public use. This rate schedule will continue to be available to fixtures that were being served hereunder on July 1, 2004, and will not be available for the addition of new fixtures.

CHARACTER OF SERVICE
These rates cover electric lighting service to Company-owned and maintained street lighting equipment as hereinafter described. Service under these rates will be available on an automatically controlled dusk-to-dawn every-night schedule of approximately 4,000 hours per year, and only to the types of lighting units specified herein.

RATES

Type of Unit	Rate Per Month Per Unit: Installed Prior to January 1, 1991	Installed After December 31, 1990
Overhead Service		
Mercury Vapor		
100 Watt	$ 7.20	N/A
175 Watt	8.40	$10.19
250 Watt	9.72	11.61
400 Watt	11.88	14.19
400 Watt (metal pole)	16.39	N/A
1000 Watt	22.72	26.43
High Pressure Sodium Vapor		
100 Watt	$ 9.70	$ 9.70
150 Watt	11.52	11.52
150 Watt Flood	13.85	11.52
250 Watt	13.86	13.86
400 Watt	14.97	14.97
1000 Watt	N/A	33.92
Underground Service		
Mercury Vapor		
100 Watt - Top Mounted	$11.20	$13.89
175 Watt - Top Mounted	12.30	14.83
175 Watt (metal pole)	16.33	23.27
250 Watt	17.69	24.20
400 Watt	21.09	27.33
400 Watt on State of Ky. Pole	21.19	21.19
High Pressure Sodium Vapor		
70 Watt - Top Mounted	N/A	$13.39
100 Watt - Top Mounted	$13.99	13.99
150 Watt - Top Mounted	N/A	20.25
150 Watt	23.50	23.50
250 Watt	25.20	25.20
250 Watt (metal pole)	25.20	25.20
250 Watt on State of Ky. Pole	22.27	22.27
400 Watt	27.49	27.49
400 Watt (metal pole)	27.49	27.49
1000 Watt	N/A	63.70

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 36.3

Standard Rate RLS
Restricted Lighting Service

TERM OF CONTRACT T
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. 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 36.4
Canceling P.S.C. Electric No. 8, First Revision of Original Sheet No. 36.4

Standard Rate — RLS

Restricted Lighting Service

Type of Unit	Installed Prior to January 1, 1991	Installed After December 31, 1990
Overhead Service		
Incandescent		
100 Watt	$ 8.42	$ 8.42
300 Watt	11.76	11.76

Decorative Lighting Service	Rate Per Month Per Unit
Fixtures	
Acorn with Decorative Basket	
70 Watt High Pressure Sodium	$18.00
100 Watt High Pressure Sodium	18.91
8-Sided Coach	
70 Watt High Pressure Sodium	$18.21
100 Watt High Pressure Sodium	19.51
Poles	
10' Smooth	$10.44
10' Fluted	12.46
Bases	
Old Town / Manchester	$ 3.35
Chesapeake / Franklin	3.60
Jefferson / Westchester	3.62
Norfolk / Essex	3.81

NA – Not Available

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

SPECIAL TERMS AND CONDITIONS

1. Overhead Service. The above rates contemplate installation on an existing pole in Company's system. If the location of an existing pole is not suitable for the installation of a lighting unit, the Company will extend its secondary conductor one span and install an additional pole for the support of such unit. If still further poles or conductors are required to extend service to the lighting unit, the customer will be required to make a non-refundable cash advance equal to the installed cost of such further 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

The proposed LG&E Restricted Lighting Service Rate RLS is contained on four pages instead of the current six pages.

2. Underground Service. In all areas other than the downtown section of the City of Louisville designated by City ordinance as an underground district, the Company will provide a normal installation consisting of a direct buried cable connection of not more than 200 feet per unit. If additional facilities or expenditures are required, including any additional cost to break pavement or remove rock, the customer shall make a non-refundable cash advance equivalent to the excess costs. Company may decline to install equipment and provide service thereto in locations deemed by Company unsuitable for underground installation.

   Within the aforesaid City of Louisville underground district, the Company will provide underground facilities in accordance with sound engineering practices.

3. **DECORATIVE LIGHTING SERVICE.** The monthly rates for Decorative Lighting are calculated as the sum of the rates for the individual elements of the customized light. For example, the monthly rate will be calculated as the sum of the rates for the chosen fixture style and wattage, the chosen pole style, and the chosen base style, if one is chosen. This provides flexibility for the Company to meet the individual desires of each Decorative Lighting customer.

4. Company will furnish and install the complete lighting unit. All lighting units, including poles, standards and conductors installed in accordance herewith shall be the property of Company, and Company shall have access to the same for maintenance, inspection and all other proper purposes. Company shall have the right to make other attachments to the poles and to further extend the conductors installed in accordance herewith when necessary for the further extension of its electric service.

5. Customer shall be responsible for any permit or authorization that may be required for the installation of the lighting units at the specified locations.

6. Company may decline to install equipment and provide service thereto in locations where, in Company's judgment, such equipment will be subject to unusual hazards or risk of damage.

7. Contracts for this service shall have a minimum fixed term of five 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 nonpayment of bill or other causes set forth in its General Rules and Regulations. Upon permanent discontinuance of service, lighting units and other equipment will be removed.

8. Nothing herein shall prevent Company and Customer from taking into account unusual circumstances and agreeing on modifications of the above rates commensurate with such circumstances, provided such agreement are duly filed with and made subject to the jurisdiction of the Public Service Commission of Kentucky.

9. Mercury Vapor is restricted to those fixtures in service prior to July 22, 2007. Upon failure, existing fixtures will either be removed from service or replaced with available lighting at the customer's option.

TERMS AND CONDITIONS

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

The proposed LG&E Restricted Lighting Service Rate RLS is contained on four pages instead of the current six pages.

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 37
Canceling P.S.C. Electric No. 8, 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
$0.05646 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
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 types of equipment served.
2. 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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
$0.05942 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
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 types of equipment served.
2. 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Third Revision of Original Sheet No. 38
Cancelling P.S.C. Electric No. 8, 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: $0.06804 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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: $0.07178 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 39
Canceling P.S.C. Electric No. 8, 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	$22.64
DSK Lantern	9,500	.100	$23.62

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. Charges listed under **RATE** are based on a normal installation with a direct buried cable connection of up to 200 feet 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 facilities are required, Customer shall make a non-refundable cash advance equivalent to the installed cost of such excess 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

The current LG&E Dark Sky Friendly Rate DSK is proposed to be included in Lighting Service Rate LS.

Louisville Gas and Electric Company

Standard Rate | **DSK**

Dark Sky Friendly

SPECIAL TERMS AND CONDITIONS (continued)

3. 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.

4. 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.

5. 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.

6. 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.

7. 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.

8. 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.

9. 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.

10. 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, Louisville, Kentucky

The current LG&E Dark Sky Friendly Rate DSK is proposed to be included in Lighting Service Rate LS.

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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

$5.35 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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

$9.42 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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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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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, Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 40.1

Standard Rate — CTAC

Cable Television Attachment Charges

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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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Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 40.3

Standard Rate CTAC

Cable Television Attachment Charges

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Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 40.4

Standard Rate | **CTAC**

Cable Television Attachment Charges

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 Louisville Gas and Electric 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 Louisville Gas and Electric Company. This insurance may not be canceled for any cause without sixty (60) days advance written notice being first given to Louisville Gas and Electric 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.

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Standard Rate | **CTAC**

Cable Television Attachment Charges

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Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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).

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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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Standard Rate CTAC
Cable Television Attachment Charges

(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.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Standard Rate CTAC
Cable Television Attachment Charges

(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. T

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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 $29.00 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. If both gas and electric services are reconnected at the same time, the total charge for restoration of both services shall be $29.00. 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 $29.00 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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. If both gas and electric services are reconnected at the same time, the total charge for restoration of both services shall be $28.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection. R R

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. R

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.

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

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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. 8, CSR10 and CSR30 for Louisville Gas and Electric Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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. 9, CSR10 and CSR30 for Louisville Gas and Electric Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric 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 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, Louisville, 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 T
billed) immediately prior to the curtailment less the designated curtailable load. T
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 T
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	\$ 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 T
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.

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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. 8, CSR10 and CSR30 for Louisville Gas and Electric Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric 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.

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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. 9, CSR10 and CSR30 for Louisville Gas and Electric Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric 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
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Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

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 measured on the T
demand basis of the standard rate on which Customer is billed) immediately prior T
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 T
preceding – Designated Curtailable kVA) x hours of requested curtailment]}. Non- T
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.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

The current LG&E Load Reduction Incentive Rider LRI is proposed to be eliminated.

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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. T

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

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:

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:

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

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

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

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.

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.

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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.

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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, $C_{LG\&E}$ 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.

Date of Issue: August 6, 2010
Date Effective: November 1, 1995
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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, $C_{LG\&E}$ 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.

Date of Issue: June 29, 2012
Date Effective: November 1, 1995
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Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 56.1

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

1. System demand is less than or equal to Company's capacity:
   $D_I \leq C_{LG\&E}$; $CAP_I = 0$

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:

   $C_{LG\&E} < D_I \leq [C_{LG\&E} + C_{QF}]$; $CAP_I = C_M$

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

   $D_I > [C_{LG\&E} + C_{QF}]$; $CAP_I = C_{QF}$

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.

Date of Issue: August 6, 2010
Date Effective: November 1, 1995
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 56.1

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

1. System demand is less than or equal to Company's capacity:
   $D_I \leq C_{LG\&E}$; $CAP_I = 0$

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:

   $C_{LG\&E} < D_I \leq [C_{LG\&E} + C_{QF}]$; $CAP_I = C_M$

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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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Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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

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Date Effective: August 17, 2009
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Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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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NET METERING SERVICE INTERCONNECTION GUIDELINES

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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

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Date Effective: August 17, 2009
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Louisville Gas and Electric Company

P.S.C. Electric No. 8, First Revision of Original Sheet No. 57.1
Canceling P.S.C. Electric No. 8, Original Sheet No. 57.1

Standard Rate Rider — NMS
Net Metering Service

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.

Date of Issue: February 2, 2012
Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 57.1

Standard Rate Rider — NMS
Net Metering Service

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.

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Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 57.2

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

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 57.2

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

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Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 57.4

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.

Date of Issue: August 6, 2010
Date Effective: August 17, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 57.4

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.

Date of Issue: June 29, 2012
Date Effective: April 17, 1999
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

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:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E 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 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:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E 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: ______________________

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:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E 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: ____________

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:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E 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: ____________

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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 1.66%

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 0.86%

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 60

Standard Rate Rider EF

Excess Facilities

APPLICABILITY

In all territory served.

AVAILABILITY OF SERVICE

This rider is available for non-standard service facilities which are considered to be in excess of T
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 1.37% 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 0.55% 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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 Customer's facility in the event that an emergency or unusual occurrence renders Customer's principal delivery unavailable for providing service.

RATE:

Capacity Reservation Charge

Secondary Distribution	$1.52 per kW per Month
Primary Distribution	$1.13 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 (1) 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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 Customer's facility in the event that an emergency or unusual occurrence renders 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	$1.13 per kW/kVA per Month	R/T
Primary Distribution	$0.88 per kW/kVA per Month	R/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 (1) 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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:	$8.23	$7.21	$6.08

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 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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:	$13.14	$12.50	$11.28	T/I

CONTRACT DEMAND

Contract Demand is defined as the number of kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) mutually agreed upon as representing 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 Customer is billed) 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. T T T T

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 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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 the 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 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 therefore 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
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Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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 the 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 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 therefore 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

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 67

Standard Rate Rider

Kilowatt-Hours Consumed By Street 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.

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 67

Standard Rate Rider

Kilowatt-Hours Consumed By Lighting Units T

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: 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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 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 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.

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Issued by Authority of an Order of the KPSC in Case No. 2009-00467 dated February 22, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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 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 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.

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Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 70.1

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 IPS, CPS, ITOD, CTOD, 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 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 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.

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 70.1

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 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 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.

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Issued by Authority of an Order of the KPSC in Case No. 2009-00467 dated February 22, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, First Revision of Original Sheet No. 71
Canceling P.S.C. Electric No. 8, 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 ITODS, ITODP, CTODS, CTODP, 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 kW as is appropriate) 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 (or kW as is appropriate); and
   2) existing customers contracting for a minimum annual average of monthly billing load of 1,000 kVA (or kW as is appropriate) 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00103 dated August 11, 2011

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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. T

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 kW as is appropriate) 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 (or kW as is appropriate); and
   2) existing customers contracting for a minimum annual average of monthly billing load of 1,000 kVA (or kW as is appropriate) above their Existing Base Load, to be determined 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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.

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

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00103 dated August 11, 2011

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. Electric No. 6 CTOD, ITOD, 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. 2009-00549. 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00010 dated March 20, 2012

The current LG&E Real-Time Pricing Rider RTP is proposed to be eliminated.

Louisville Gas and Electric Company

Standard Rate Rider RTP

Real-Time Pricing Rider

CUSTOMER BASELINE LOAD (CBL)

The CBL is based on one complete calendar year of hourly kVA firm 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 provided 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00010 dated April 9, 2012

The current LG&E Real-Time Pricing Rider RTP is proposed to be eliminated.

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 79
Canceling P.S.C. Electric No. 8, 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:	$0.05046 per kWh
Intermediate Hours:	$0.07070 per kWh
Peak Hours:	$0.13448 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated January 31, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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:	$ 0.05235 per kWh	I
Intermediate Hours:	$ 0.07335 per kWh	I
Peak Hours:	$ 0.13951 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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
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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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 85

Adjustment Clause FAC

Fuel Adjustment Clause

APPLICABLE.
In all territory service.

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 nonscheduled 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 85

Adjustment Clause FAC

Fuel Adjustment Clause

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

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(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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, First Revision of Original Sheet No. 85.1
Canceling P.S.C. Electric No. 8, 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 $0.02215 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. 2010-00493 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2010-00493 dated May 31, 2011

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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 $0.02215 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. 2010-00493 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2010-00493 dated May 31, 2011

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 86
Canceling P.S.C. Electric No. 8, First Revision of 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 Rate VFD, General Service Rate GS, Power Service Rate PS, Industrial Time-of-Day Secondary Service Rate ITODS, Commercial Time-of-Day Secondary Service Rate CTODS, Industrial Time-of-Day Primary Service Rate ITODP, Commercial Time-of-Day Primary Service Rate CTODP, Retail Transmission Service Rate RTS, 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,

Date of Issue: April 30, 2012
Date Effective: May 31, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00440 dated March 22, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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 Rate VFD, General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, Retail Transmission Service Rate RTS, 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 T 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, and LEV customer classes is defined as the weighted average price per kWh of expected 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 86.1
Canceling P.S.C. Electric No. 8, First Revision of Original Sheet No. 86.1

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

RATE (continued)

and LEV customer classes is defined as the weighted average price per kWh of expected billings under the energy charges contained in the RS, VFD, GS, 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, ITODS, CTODS, ITODP, and CTODP) 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 thirty-six (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, Power Service Rate PS, Commercial

Date of Issue: April 30, 2012
Date Effective: May 31, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00440 dated March 22, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 86.1

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

RATE (continued)

billings under the energy charges contained in the RS, VFD, GS, 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. T T

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 thirty-six (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, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Low Emission Vehicle Service Rate shall be divided by the expected kilowatt-hour sales for the 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 86.2
Canceling P.S.C. Electric No. 8, First Revision of Original Sheet No. 86.2

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

Time-of-Day Secondary Service Rate CTODS, and Commercial Time-of-Day Primary Service Rate CTODP, 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.

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.

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 86.2

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

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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.

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Louisville Gas and Electric Company

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

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

The filing of modifications to the DSMRC that require changes in the DCR component shall be made at least two months prior to the beginning of the effective period for billing.

Modifications to other components of the DSMRC shall be made at least thirty (30) 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.

Louisville Gas and Electric Company

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

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Louisville Gas and Electric Company

P.S.C. Electric No. 8, Fourth Revision of Original Sheet No. 86.4
Canceling P.S.C. Electric No. 8, Third Revision of Original Sheet No. 86.4

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

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 LG&E'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.

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 86.4

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

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Louisville Gas and Electric Company

P. S. C. Electric No. 8, First Revision of Original Sheet No. 86.5
Canceling P.S.C. Electric No. 8, Original Sheet No. 86.5

Adjustment Clause DSM
Demand-Side Management Cost Recovery Mechanism

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 LG&E 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. LG&E will reimburse the cost of plan reviews and inspection costs related to an Energy Star or HERS home certification.

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Adjustment Clause DSM
Demand-Side Management Cost Recovery Mechanism

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Louisville Gas and Electric Company

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

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, PS, ITODS, CTODS, ITODP, CTODP, and RTS 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.

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Louisville Gas and Electric Company

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Demand-Side Management Cost Recovery Mechanism

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Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

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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Louisville Gas and Electric Company

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 until 10MW 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.

Louisville Gas and Electric Company

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

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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 50 kW demand reduction per control event. The Company will continue to enroll program participants until 10MW curtailable load is achieved. T

- $25 per kW for verified load reduction during June, July, August, & September. T
- The customer will have access to at least hourly load data for every month of the year which they remain enrolled in the program.

Louisville Gas and Electric Company

P.S. C. Electric No. 8, Original Sheet No. 86.9

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

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

Date of Issue: April 30, 2012
Date Effective: May 31, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 86.9

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

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

Date of Issue: June 29, 2012
Date Effective: May 31, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 86.10

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Residential Rate RS, Volunteer
Fire Department Rate VFD, and
Low Emission Vehicle Service LEV

	Energy Charge
DSM Cost Recovery Component (DCR)	\$ 0.00147 per kWh
DSM Revenues from Lost Sales (DRLS)	\$ 0.00154 per kWh
DSM Incentive (DSMI)	\$ 0.00007 per kWh
DSM Capital Cost Recovery Component (DCCR)	\$ 0.00049 per kWh
DSM Balance Adjustment (DBA)	\$ (0.00070) per kWh
Total DSMRC for Rates RS, VFD, and LEV	\$ 0.00287 per kWh

General Service Rate GS

	Energy Charge
DSM Cost Recovery Component (DCR)	\$ 0.00076 per kWh
DSM Revenues from Lost Sales (DRLS)	\$ 0.00158 per kWh
DSM Incentive (DSMI)	\$ 0.00004 per kWh
DSM Capital Cost Recovery Component (DCCR)	\$ 0.00007 per kWh
DSM Balance Adjustment (DBA)	\$ (0.00004) per kWh
Total DSMRC for Rates GS and GRP	\$ 0.00241 per kWh

Commercial Service Under Power Service Rate PS

	Energy Charge
DSM Cost Recovery Component (DCR)	\$ 0.00025 per kWh
DSM Revenues from Lost Sales (DRLS)	\$ 0.00084 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 Rate PS	\$ 0.00111 per kWh

Commercial Time-of-Day Secondary Service Rate CTODS
and Commercial Time-of-Day Primary Service Rate CTODP

	Energy Charge
DSM Cost Recovery Component (DCR)	\$ 0.00022 per kWh
DSM Revenues from Lost Sales (DRLS)	\$ 0.00070 per kWh
DSM Incentive (DSMI)	\$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	\$ 0.00000 per kWh
DSM Balance Adjustment (DBA)	\$ (0.00004) per kWh
Total DSMRC for Rates CTODS and CTODP	\$ 0.00089 per kWh

Date of Issue: April 30, 2012
Date Effective: April 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 86.10

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Residential Rate RS, Volunteer
Fire Department Rate VFD, and
Low Emission Vehicle Service Rate LEV

	Energy Charge	T
DSM Cost Recovery Component (DCR)	\$ 0.00147 per kWh	
DSM Revenues from Lost Sales (DRLS)	\$ 0.00154 per kWh	
DSM Incentive (DSMI)	\$ 0.00007 per kWh	
DSM Capital Cost Recovery Component (DCCR)	\$ 0.00049 per kWh	
DSM Balance Adjustment (DBA)	\$ (0.00070) per kWh	
Total DSMRC for Rates RS, VFD, and LEV	\$ 0.00287 per kWh	

General Service Rate GS

	Energy Charge	
DSM Cost Recovery Component (DCR)	\$ 0.00076 per kWh	
DSM Revenues from Lost Sales (DRLS)	\$ 0.00158 per kWh	
DSM Incentive (DSMI)	\$ 0.00004 per kWh	
DSM Capital Cost Recovery Component (DCCR)	\$ 0.00007 per kWh	
DSM Balance Adjustment (DBA)	\$ (0.00004) per kWh	
Total DSMRC for Rates GS	\$ 0.00241 per kWh	T

Commercial Customers Served Under Power Service Rate PS

	Energy Charge	T
DSM Cost Recovery Component (DCR)	\$ 0.00025 per kWh	
DSM Revenues from Lost Sales (DRLS)	\$ 0.00084 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 Rate PS	\$ 0.00111 per kWh	

Commercial Customers Served Under Time-of-Day Secondary T
Service Rate TODS and Time-of-Day Primary Service Rate TODP

	Energy Charge	T
DSM Cost Recovery Component (DCR)	\$ 0.00022 per kWh	
DSM Revenues from Lost Sales (DRLS)	\$ 0.00070 per kWh	
DSM Incentive (DSMI)	\$ 0.00001 per kWh	
DSM Capital Cost Recovery Component (DCCR)	\$ 0.00000 per kWh	
DSM Balance Adjustment (DBA)	\$ (0.00004) per kWh	
Total DSMRC for Rates TODS, and TODP	\$ 0.00089 per kWh	T

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

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 86.11

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Industrial Service Under Rate PS,
Industrial Time-of-Day Secondary Service Rate ITODS
Industrial Time-of-Day Primary Service Rate ITODP,
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, ITODS, ITODP, and RTS	$ 0.00000	per kWh

Date of Issue: April 30, 2012
Date Effective: With Bills Rendered On and After December 30, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00134 dated November 9, 2011

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 86.11

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Industrial Customers Served Under Power Service Rate PS, T
Time-of-Day Secondary Service Rate TODS, Time-of-Day T
Primary Service Rate TODP, and Retail Transmission Rate RTS T

	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	T

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00134 dated November 9, 2011

Louisville Gas and Electric Company

P.S.C. Electric No. 8, First Revision of Original Sheet No. 87
Canceling P.S.C. Electric No. 8, 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; LS; RLS; DSK; LE; TE; and Pilot Programs RRP and LEV.
Group 2: Rate Schedules GS; PS; ITODS; CTODS; ITODP; CTODP: RTS; FLS; and Pilot Program GRP.

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, 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: May 14, 2012
Date Effective: February 29, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated February 29, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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; LS; RLS; LE; TE; and Pilot Program LEV. T
Group 2: Rate Schedules GS; PS; TODS; TODP; RTS; and FLS. T

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, First Revision of Original Sheet No. 87.1
Canceling P.S.C. Electric No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated February 29, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00232 dated February 29, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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: June 29, 2012
Date Effective: October 16, 2003
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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: June 29, 2012
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Second Revision of Original Sheet No. 92
Canceling P.S.C. Electric No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00162 dated December 15, 2011

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00162 dated December 15, 2011

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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, Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 96

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Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 97

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 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 months.

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Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 97.1

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 customers 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.

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Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 97.2

TERMS AND CONDITIONS

Customer Responsibilities

POWER FACTOR

Company installs facilities to supply power to its customers 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 the 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 contracted 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 the 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, 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

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Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 97.3

TERMS AND CONDITIONS
Customer Responsibilities

PERMITS (continued)

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 the 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.

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P.S.C. Electric No. 9, Original Sheet No. 97.3

TERMS AND CONDITIONS

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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 with 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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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 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).

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 99

TERMS AND CONDITIONS

Character of Service

Electric service, under the rate schedule 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 three-wire service where network system is available.
2) Three phase 240 volts three-wire, 480 volts three-wire service, 120/208Y volts four-wire service, or 277/480Y volts four-wire service.

PRIMARY VOLTAGES

According to location, 2400/4160Y volts, 7200/12,470Y volts, 13,800 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 such customer's electric load is located.

RESTRICTIONS

1. Except for minor loads, with approval of the 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, a 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 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 the 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 99

TERMS AND CONDITIONS

Character of Service

Electric service, under the rate schedule 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 three-wire service where network system is available.
2) Three phase 240 volts three-wire, 480 volts three-wire service, 120/208Y volts four-wire service, or 277/480Y volts four-wire service.

PRIMARY VOLTAGES

According to location, 2400/4160Y volts, 7200/12,470Y volts, 13,800 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 such customer's electric load is located.

RESTRICTIONS

1. Except for minor loads, with approval of the 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, a 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 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 the 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 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 (2) 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.

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:

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 (2) 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.

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:

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 100.1

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

(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.

Date of Issue: August 6, 2010
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 100.1

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

(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.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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 customer 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.

Where Company serves a customer with both electric and gas service at the same service location, Company will render a combined bill. Provided, however, a residential customer may request, and Company will render, separate bills under the following conditions: (1) Customer is being threatened with disconnection for non-payment or has already been disconnected for that reason and (2) Customer would be able to pay either the gas or electric portion of his bill and thus retain one service.

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.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 101

TERMS AND CONDITIONS

BILLING

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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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 101.1

TERMS AND CONDITIONS

BILLING

READING OF SEPARATE METERS NOT COMBINED

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

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 the 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 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 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 101.1

TERMS AND CONDITIONS

BILLING

READING OF SEPARATE METERS NOT COMBINED

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

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

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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, Louisville, Kentucky

The Billing section of the proposed LG&E Terms and Conditions is contained on four pages instead of the current two pages.

TERMS AND CONDITIONS

BILLING

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. T

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.

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 the 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 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).

The Billing section of the proposed LG&E Terms and Conditions is contained on four pages instead of the current two pages.

TERMS AND CONDITIONS

BILLING

RESALE OF ELECTRIC ENERGY T

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 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.

Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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 KAR5:006, Section 7(1)(b). For combination gas and electric customers, the total deposit will be $250.00.
3) Company shall 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 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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Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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 KAR5:006, Section 7(1)(b). For combination gas and electric customers, the total deposit will be $230.00. R
3) Company shall 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 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.

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

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 102.1

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 KAR5:006, 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 percent (10%), 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 KAR5:006, 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 percent (10%), 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 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.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 102.1

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 KAR5:006, 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 energy usage is no more than 300 kWh per month. T T T T
2) Company shall 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 percent (10%), 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 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 KAR5:006, 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 percent (10%), 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 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.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 103

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 the 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 Customer's next budget year.

If Customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove 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 Customer from the provisions of these terms and conditions.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 103

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 the 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 Customer's next budget year.

If Customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove 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 Customer from the provisions of these terms and conditions.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

Bill Format

a PPL company

Customer Service: 1-800-331-7370 (M-F, 7 a.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: 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	$28.53

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 you account number available when calling to discuss your account.

ACCOUNT INFORMATION

Account Number:	3000-1111-2222
Account Name:	JOHN DOE
Service Address:	1234 Main St LOUISVILLE KY
Next Read Will Occur:	12/12/11 - 12/14/11
Date Bill Mailed:	11/16/11 (Meter Read Portion 10)

Averages for Billing Period	This Year	Last Year
Average Temperature	53°	58°
Number of Days Billed	28	0
Electric/kwh per day	9.1	0.00
Gas/ccf per day	1.4	0.00

BILLING SUMMARY

Previous Balance		23.07
Payment(s) Received 10/15 - 11/15		-23.07
Balance as of 11/15		0.00
Current Electric Charges	28.53	
Current Charges as of 11/15		28.53
Total Amount Due		28.53

ELECTRIC CHARGES

Rate Type: Residential Electric Service		**Meter Reading Information**	
Basic Service Charge	8.50	Meter # 70000	
Energy Charge ($0.07225 x 255.00 kwh)	18.42	Actual Reading on 11/11/11	257
		Previous Reading on 10/14/11	2
Other Charges For Above Rates			
Electric Fuel Adjustment ($0.00307 x 255 kwh)	0.78	**Current kwh Usage**	255
Electric DSM ($0.00244 x 255.00 kwh)	0.62	Meter Multiplier	1
Environmental Surcharge (0.210% x $28.32)	0.06	**Metered kwh Usage**	255
Home Energy Assistance Fund Charge	0.15		
Total Electric Charges	$28.53		

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

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	$28.53	$29.96	$	$

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

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

PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900082 4#
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40028-8746

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, Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format

T

a PPL company

Customer Service: 1-800-331-7370 (M-F, 7 a.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: 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
04/24/12	$71.03

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 you account number available when calling to discuss your account.

ACCOUNT INFORMATION

Account Number:	3000-1111-2222
Account Name:	JOHN DOE
Service Address:	1234 Main St LOUISVILLE KY
Next Read Will Occur:	05/08/12 - 05/10/12
Date Bill Mailed:	04/11/12 (Meter Read Portion 07)

Averages for Billing Period	This Year	Last Year
Average Temperature	63°	54°
Number of Days Billed	32	29
Electric/kwh per day	24.3	19.60

BILLING SUMMARY

Previous Balance		136.16
Payment(s) Received 3/10 - 4/11		-136.16
Balance as of 4/11		0.00
Current Electric Charges	71.30	
Current Charges as of 4/11		71.30
Total Amount Due		71.30

ELECTRIC CHARGES

Rate Type: Residential Electric Service		**Meter Reading Information**	
Basic Service Charge	8.50	Meter # 70000	
Energy Charge ($0.07242 x 778.00 kwh)	56.34	Actual Reading on 4/10/12	13124
Electric DSM ($0.00287 x 778 kwh)	2.23	Previous Reading on 3/9/12	12346
Electric Fuel Adjustment ($0.00472 x 778.00 kwh)	3.67	**Current kwh Usage**	778
Environmental Surcharge (0.560% x $70.74)	0.40	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.16	**Metered kwh Usage**	778
Total Electric Charges	$71.30		

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

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	04/24/12	$71.30	$74.87	$	$

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

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

PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900082 4#
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40028-8746

Service Address: 1234 Main 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, First Revision of Original Sheet No. 104.1
Canceling P.S.C. Electric No. 8, Original Sheet No. 104.1

TERMS AND CONDITIONS

Bill Format

Account Number 3000-1111-2222 Page 2

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date $1.42

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.

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 510 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 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 LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 104.1

TERMS AND CONDITIONS

Bill Format

Account Number 3000-1111-2222 Page 2

T

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date $3.57

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 1,556 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 LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

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: 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, First Revision of Original Sheet No. 104.2
Canceling P.S.C. Electric No. 8, Original Sheet No. 104.2

TERMS AND CONDITIONS
Bill Format

LG&E
a PPL company

Customer Service:	1-800-331-7370 (M-F, 7 a.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:	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	$71.82

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 you account number available when calling to discuss your account.

ACCOUNT INFORMATION

Account Number:	3000-1111-2222
Account Name:	JOHN DOE
Service Address:	1234 Main St LOUISVILLE KY
Next Read Will Occur:	12/12/11 - 12/14/11
Date Bill Mailed:	11/16/11 (Meter Read Portion 10)

Averages for Billing Period	This Year	Last Year
Average Temperature	53°	58°
Number of Days Billed	28	0
Electric/kwh per day	9.1	0.00
Gas/ccf per day	1.4	0.00

BILLING SUMMARY

Previous Balance		23.07
Payment(s) Received 10/15-11/15		-23.07
Balance as of 11/15		0.00
Current Electric Charges	28.53	
Current Gas Charges	43.29	
Current Charges as of 11/15		71.82
Total Amount Due		71.82

ELECTRIC CHARGES

Rate Type: Residential Electric Service		**Meter Reading Information**	
Basic Service Charge	8.50	Meter # 704252	
Energy Charge ($0.07225 x 255.00 kwh)	18.42	Actual Reading on 11/11/11	257
		Previous Reading on 10/14/11	2
Other Charges For Above Rates			
Electric Fuel Adjustment ($0.00307 x 255 kwh)	0.78	Current kwh Usage	255
Electric DSM ($0.00244 x 255.00 kwh)	0.62	Meter Multiplier	1
Environmental Surcharge (0.210% x $28.32)	0.06	Metered kwh Usage	255
Home Energy Assistance Fund Charge	0.15		
Total Electric Charges	$28.53		

Please see reverse side for additional charges.

Customer Service 1-800-331-7370 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	$71.82	$75.41	$	$

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

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

LG&E
PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900082 4E
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40028-8746

Service Address: 1234 Main St

020000000000000000000000124560000001189150000000000000

Date of Issue: December 22, 2011
Date Effective: December 22, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 104.2

TERMS AND CONDITIONS

T

Bill Format

LG&E
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
04/24/12	$122.18

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:	3000-0216-5900-28
Account Name:	JOHN DOE
Service Address:	1234 ANYWHERE ST
Next Read Will Occur:	05/08/12 - 05/10/12
Date Bill Mailed:	04/11/12 (Meter Read Portion 07)

BILLING SUMMARY

Previous Balance		102.30
Payment(s) as of 3/10 - 4/11		(102.30)
Balance as of 4/11		0.00
Electric Charges	71.30	
Gas Charges	50.88	
Utility Charges as of 08/20		122.18
Other Charges		
Total Amount Due		122.18

Averages for Billing Period	This Year	Last Year
Average Temperature	63 °	54 °
Number of Days Billed	32	29
Electric/kwh per day	24.3	10.6
Gas/ccf per day	1.0	2.2

ELECTRIC CHARGES

Rate Type: Residential Electric Service		**Meter Reading Information**	
Basic Service Charge	8.50	Meter # 70000	
Energy Charge ($0.07242 x 778.00 kwh)	56.34	Actual Reading on 4/10/12	13124
Electric DSM ($0.00287 x 778 kwh)	2.23	Previous Reading on 3/9/12	12346
Electric Fuel Adjustment ($0.00472 x 778.00 kwh)	3.67	Current kwh Usage	778
Environmental Surcharge (0.560% x $70.74)	0.40	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.16	Metered kwh Usage	778
Total Electric Charges	$71.30		

Please see reverse side for additional charges.

Customer Service 1-800-331-7370 PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number	Payment Due Date	Amount Due by Due Date	Amount Due 6 Days After Due Date	Winter Help Donation	Amount Enclosed
3000-0216-5900-28	04/24/12	$122.18	$128.29	$	$

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

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

LG&E
PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131990082 4E
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40028-8746

Service Address: 1234 Main St

020000000000000000000000124560000001189150000000000000

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, Louisville, Kentucky

TERMS AND CONDITIONS
Bill Format

Account Number 3000-1111-2222 Page 2

GAS CHARGES

Rate Type: Residential Gas Service		**Meter Reading Information**	
Basic Service Charge	12.50	Meter # 499779	
Gas Distribution Charge ($0.22396 x 41 ccf)	9.18	Actual Reading on 11/11/11	6057
Gas Supply Component ($0.51602 x 41 ccf)	21.16	Previous Reading on 10/14/11	6016
Weather Normalization Adjustment ($0.22396 x 2.081 - ccf)	-0.47	**Current ccf Usage**	41
		Meter Multiplier	1
Other Charges For Above Rates		**Metered ccf Usage**	41
Gas DSM ($0.01887 x 41.00 ccf)	0.77		
Home Energy Assistance Fund Charge	0.15		
Total Gas Charges	$43.29		

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date $3.59

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.

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 510 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 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 LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

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.

TERMS AND CONDITIONS
Bill Format

T

Account Number 3000-0216-5900-28 Page 2

GAS CHARGES

Rate Type: Residential Gas Service		**Meter Reading Information**	
Basic Service Charge	12.50	Meter # 45678	
Gas Distribution Charge ($0.22396 x 35 ccf)	7.84	Actual Reading on 4/10/12	1922
Gas Supply Component ($0.47423 x 35 ccf)	16.60	Previous Reading on 3/9/12	1887
Weather Normalization Adjustment ($0.22396 x 58.850 ccf)	13.18	Current ccf Usage	35
Gas DSM ($0.01709 x 35.00 ccf)	0.60	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.16	**Metered ccf Usage**	35
Total Gas Charges	$50.88		

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date $6.11

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 1,556 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 LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

Signature: ______________________________

Louisville Gas and Electric Company

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 the 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 the 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 a 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 the 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 the 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 the 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

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 the 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 the 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 a 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.

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Date of Issue: June 29, 2012
Date Effective: August 1, 2010
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Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 105.1

TERMS AND CONDITIONS

Discontinuance of Service

Service will not be supplied or continued to any premises if at the time of application for service the 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 the 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 the 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 a 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 the 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: August 6, 2010
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 105.1

TERMS AND CONDITIONS

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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 Louisville Gas and Electric 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.

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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) The 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 25kVA.
2) Where Customer requires poly-phase service or transformer capacity in excess of 25kVA 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 25kVA 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 FOR 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

Line Extension Plan

C. GENERAL (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, Louisville, Kentucky

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 including the service and with the exception of Company's meter.
6) The normal point of delivery shall be at a junction device at the corner of the lot nearest Company's facilities. Customer shall bring Customer's service line to a point within 1 1/2 feet of the junction device with a sufficient length of service conductor left coiled above grade for completion of installation and connection by Company.
7) 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.
8) 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

Line Extension Plan

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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.
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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 including the service and with the exception of Company's meter.
6) The normal point of delivery shall be at a junction device at the corner of the lot nearest Company's facilities. Customer shall bring Customer's service line to a point within 1 1/2 feet of the junction device with a sufficient length of service conductor left coiled above grade for completion of installation and connection by Company.

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TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS
General (continued)

9) 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

1) Within the City of Louisville underground district or in those cases where Company's engineering or operating convenience requires the construction of an underground extension to an individual premise, the excess of the cost of an underground extension over that of an overhead extension will be at no cost.
2) In cases other than those specified in 1) above, 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 $6.15 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 $18.66 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
General (continued)

7) 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. T
8) 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.
9) 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

1) Within the City of Louisville underground district or in those cases where Company's engineering or operating convenience requires the construction of an underground extension to an individual premise, the excess of the cost of an underground extension over that of an overhead extension will be at no cost.
2) In cases other than those specified in 1) above, 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 $6.15 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 $18.66 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.

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Louisville Gas and Electric Company

P.S.C. Electric No. 8, 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 outlines in previous sections of LINE EXTENSION PLAN and the anticipated revenues do not justify the 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.
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 demand billing of the monthly electric 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No.9, Original Sheet No. 106.4

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS (continued)

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. T T T

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.
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   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.
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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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 107

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PURPOSE

To provide procedures for reducing the consumption of electric energy on the Louisville Gas and Electric 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, Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that 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 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 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.

Date of Issue: August 6, 2010
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 107

TERMS AND CONDITIONS

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Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 107.1

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 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.

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Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 107.1

TERMS AND CONDITIONS

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Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 8, Original Sheet No. 107.2

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: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 107.2

TERMS AND CONDITIONS

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Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

P.S.C. Gas No. 8
Canceling P.S.C. Gas No. 7

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky

Rates, Terms and Conditions for Furnishing

NATURAL GAS SERVICE

In the sixteen counties of the Louisville, Kentucky, metropolitan area
as depicted on territorial maps as filed with the

PUBLIC SERVICE COMMISSION

OF KENTUCKY

Date of Issue	Date Effective
August 6, 2010	August 1, 2010

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

P.S.C. Gas No. 9
Canceling P.S.C. Gas No. 8

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky

Rates, Terms and Conditions for Furnishing

NATURAL GAS SERVICE

In the seventeen counties of the Louisville, Kentucky, metropolitan area
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

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Fourteenth Revision of Original Sheet No. 1
Canceling P.S.C. Gas No. 8, Thirteenth Revision of Original Sheet No. 1

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CGS	Firm Commercial Gas Service	10	05-01-12
IGS	Firm Industrial Gas Service	15	05-01-12
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SECTION 2 – Riders to Standard Rate Schedules			
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Date of Issue: April 30, 2012
Date Effective: May 31, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 1

GENERAL INDEX
Standard Gas Rate Schedules – Terms and Conditions

	Title	Sheet Number	Effective Date	
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AAGS	As-Available Gas Service	20	08-01-12	
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DGGS	Distributed Generation Gas Service	35	08-01-12	
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	Meter Test Charge			
	Disconnect/Reconnect Service Charge			
	Inspection Charge			
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TS	Gas Transportation Service/Standby	50	08-01-12	T
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EF	Excess Facilities	62	08-01-12	
SECTION 3 – Adjustment Clauses				
GLT	Gas Line Tracker	84	08-01-12	T
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Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 1.1
Canceling P.S.C. Gas No. 8, Original Sheet No. 1.1

GENERAL INDEX
Standard Gas Rate Schedules – Terms and Conditions

Date of Issue: December 22, 2011
Date Effective: December 22, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 1.1

GENERAL INDEX
Standard Gas 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Seventh Revision of Original Sheet No. 5
Canceling P.S.C. Gas No. 8, Sixth Revision of Original Sheet No. 5

Standard Rate RGS
Residential Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to residential customers for all domestic purposes in private residences, single occupancy apartments, and common-use areas of multi-purpose occupancy buildings when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served. Such customers also include tenants billed for natural gas consumption or use by other tenants at the same premises that are metered separately.

The term "residential" customers shall include customers using gas in a single-family residential dwelling or unit for space-heating, air conditioning, cooking, water-heating, incineration, refrigeration, laundry drying, lighting, incidental heating, or other domestic purposes, including the use of gas in standby electric generation in domestic applications. If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation ninety (90) days or more after the effective date of Rate DGGS, customer shall be served under Standard Rate DGGS.

RATE

Basic Service Charge:	$12.50 per delivery point per month
Plus a Charge Per 100 Cubic Feet:	
Distribution Cost Component	$ 0.22396
Gas Supply Cost Component	$ 0.34904
Total Gas Charge Per 100 Cubic Feet	$ 0.57300

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	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.

Date of Issue: April 26, 2012
Date Effective: May 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00125 dated April 24, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 5

Standard Rate RGS
Residential Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to residential customers for all domestic purposes in private residences, single occupancy apartments, and common-use areas of multi-purpose occupancy buildings when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served. Such customers also include tenants billed for natural gas consumption or use by other tenants at the same premises that are metered separately.

The term "residential" customers shall include customers using gas in a single-family residential dwelling or unit for space-heating, air conditioning, cooking, water-heating, incineration, refrigeration, laundry drying, lighting, incidental heating, or other domestic purposes, including the use of gas in standby electric generation in domestic applications. If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS. T

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer's Representative) to the Company in conjunction with the "Notice to Company of Changes in Customer's Load" set out in the Customer Responsibilities section of the Terms and Conditions of the Company's Tariff. Additionally, service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other Customers. T

RATE

Basic Service Charge:	$15.50 per delivery point per month	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.23121	I
Gas Supply Cost Component	$ 0.34904	
Total Gas Charge Per 100 Cubic Feet	$ 0.58025	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

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, Louisville, Kentucky

Louisville Gas and Electric Company

Standard Rate RGS
Residential Gas Service

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.

Louisville Gas and Electric Company

Standard Rate RGS
Residential Gas Service

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

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	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.

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Seventh Revision of Original Sheet No. 7
Canceling P.S.C. Gas No. 8, Sixth Revision of Original Sheet No. 7

Standard Rate VFD

Volunteer Fire Department Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available, 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. If an additional separate point of delivery is requested by a volunteer fire department qualifying for aid under KRS 95A.262 to provide gas for use in standby electric generation ninety (90) days or more after the effective date of Rate DGGS, customer shall be served under Standard Rate DGGS.

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:	$12.50 per delivery point per month
Plus a Charge Per 100 Cubic Feet:	
Distribution Cost Component	$ 0.22396
Gas Supply Cost Component	$ 0.34904
Total Gas Charge Per 100 Cubic Feet	$ 0.57300

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	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: April 26, 2012
Date Effective: May 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00125 dated April 24, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 7

Standard Rate VFD

Volunteer Fire Department Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available, 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. If an additional separate point of delivery is requested by a volunteer fire department qualifying for aid under KRS 95A.262 to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS. T

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:	$15.50 per delivery point per month	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.23121	I
Gas Supply Cost Component	$ 0.34904	
Total Gas Charge Per 100 Cubic Feet	$ 0.58025	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

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

Gas Line Tracker	Sheet No. 84	T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Weather Normalization Adjustment	Sheet No. 88	
Franchise Fee and Local Tax	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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Seventh Revision of Original Sheet No. 10
Canceling P.S.C. Gas No. 8, Sixth Revision of Original Sheet No. 10

Standard Rate — CGS
Firm Commercial Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to customers engaged in commercial activities such as apartment buildings, rooming and boarding dwellings, residential hotels, multi-family row housing, duplexes, other situations where gas is supplied to consumers in two or more dwelling units designed for the primary purposes of residences, and other commercial activities when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination commercial and residential accounts shall be considered commercial if usage for commercial purposes is half or more than half of the total service over the course of a year.

The term "commercial" customers shall include customers using gas in activities related to warehousing, distributing, or selling commodities, providing professional services, wholesale and retail stores, offices, office buildings, hotels, retail bakeries, hospitals, schools, churches, religious or charitable institutions, governmental agencies, other institutions or the like (including local, state, and federal governmental agencies) and for uses other than those involved in manufacturing. Applications related to the use of gas in standby or other electric generation in commercial applications shall not be served under this rate schedule unless such facilities were installed and operating under this Standard Rate CGS before ninety (90) days after the effective date of Rate DGGS.

This schedule is also applicable to natural gas service for street lighting to such entities as certificated homeowners associations, businesses, and local, state, and federal governmental agencies.

RATE

Basic Service Charge:	
If all of the customer's meters have a capacity < 5000 cf/hr:	$ 30.00 per delivery point per month
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$170.00 per delivery point per month
Plus a Charge Per 100 Cubic Feet:	
Distribution Cost Component	$ 0.18722
Gas Supply Cost Component	0.34904
Total Charge Per 100 Cubic Feet	$ 0.53626

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

Date of Issue: April 26, 2012
Date Effective: May 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00125 dated April 24, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 10

Standard Rate — CGS
Firm Commercial Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to customers engaged in commercial activities such as apartment buildings, rooming and boarding dwellings, residential hotels, multi-family row housing, duplexes, other situations where gas is supplied to consumers in two or more dwelling units designed for the primary purposes of residences, and other commercial activities when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination commercial and residential accounts shall be considered commercial if usage for commercial purposes is half or more than half of the total service over the course of a year.

The term "commercial" customers shall include customers using gas in activities related to warehousing, distributing, or selling commodities, providing professional services, wholesale and retail stores, offices, office buildings, hotels, retail bakeries, hospitals, schools, churches, religious or charitable institutions, governmental agencies, other institutions or the like (including local, state, and federal governmental agencies) and for uses other than those involved in manufacturing. Applications related to the use of gas in standby or other electric generation in commercial applications shall not be served under this rate schedule unless (1) T
such facilities were installed and operating under this Standard Rate CGS before ninety (90) days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000 T
cubic feet per hour and are not for the generation of electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electric supplies during emergency situations.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer's Representative) to the Company in conjunction with the "Notice to Company of Changes in Customer's Load" set out in the Customer Responsibilities section of the Terms and Conditions of the Company's Tariff. Additionally, service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other Customers.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of T
2,000 cubic feet per hour under Rate DGGS shall not be permitted. T

This schedule is also applicable to natural gas service for street lighting to such entities as certificated homeowners associations, businesses, and local, state, and federal governmental agencies.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 10.1

Standard Rate CGS
Firm Commercial Gas Service

Off-Peak Pricing Provision:
The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by $0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	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: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 10.1

Standard Rate CGS
Firm Commercial Gas Service

RATE
Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 35.00 per delivery point per month	T T/I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$175.00 per delivery point per month	T T/I
Plus a Charge Per 100 Cubic Feet:		T
Distribution Cost Component	$ 0.21142	T/I
Gas Supply Cost Component	0.34904	T
Total Charge Per 100 Cubic Feet	$ 0.56046	T/I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff. T T T T

Off-Peak Pricing Provision:
The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by $0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

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

Gas Line Tracker	Sheet No. 84	T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Weather Normalization Adjustment	Sheet No. 88	
Franchise Fee and Local Tax	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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Seventh Revision of Original Sheet No. 15
Canceling P.S.C. Gas No. 8, Sixth Revision of Original Sheet No. 15

Standard Rate — IGS
Firm Industrial Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to customers engaged in industrial activities that involve manufacturing or other activities that process, create or change raw or unfinished materials into another form or product when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination industrial and commercial accounts shall be considered industrial if usage for industrial purposes is half or more than half of the total service over the course of a year.

The term "industrial" customers shall include customers involved in activities using gas primarily in a process or processes which either involve the extraction of raw materials from the earth, or a change of raw or unfinished materials into another form or product through the application of heat or heat treating, steam agitation, evaporation, baking, extraction, drying, distilling, asphalt production, and for other similar uses. Applications related to the use of gas in standby or other electric generation in industrial applications shall not be served under this rate schedule unless such facilities were installed and operating under this Standard Rate IGS before ninety (90) days after the effective date of Rate DGGS.

RATE

Basic Service Charge:	
If all of the customer's meters have a capacity < 5000 cf/hr:	\$ 30.00 per delivery point per month
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	\$170.00 per delivery point per month
Plus a Charge Per 100 Cubic Feet:	
Distribution Cost Component	\$ 0.19022
Gas Supply Cost Component	\$ 0.34904
Total Charge Per 100 Cubic Feet	\$ 0.53926

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

Off-Peak Pricing Provision:
The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by \$0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

Date of Issue: April 26, 2012
Date Effective: May 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00125 dated April 24, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 15

Standard Rate — IGS
Firm Industrial Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to customers engaged in industrial activities that involve manufacturing or other activities that process, create or change raw or unfinished materials into another form or product when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination industrial and commercial accounts shall be considered industrial if usage for industrial purposes is half or more than half of the total service over the course of a year.

The term "industrial" customers shall include customers involved in activities using gas primarily in a process or processes which either involve the extraction of raw materials from the earth, or a change of raw or unfinished materials into another form or product through the application of heat or heat treating, steam agitation, evaporation, baking, extraction, drying, distilling, asphalt production, and for other similar uses. Applications related to the use of gas in standby or other electric generation in industrial applications shall not be served under this rate schedule unless (1) such facilities were installed and operating under this Standard Rate IGS before ninety (90) days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000 cubic feet per hour and are not for the generation of electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electric supplies during emergency situations. T

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer's Representative) to the Company in conjunction with the "Notice to Company of Changes in Customer's Load" set out in the Customer Responsibilities section of the Terms and Conditions of the Company's Tariff. Additionally, Service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other Customers.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

RATE

Basic Service Charge:		
If all of the customer's meters have a capacity < 5000 cf/hr:	\$ 35.00 per delivery point per month	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	\$175.00 per delivery point per month	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	\$ 0.21523	I
Gas Supply Cost Component	\$ 0.34904	
Total Charge Per 100 Cubic Feet	\$ 0.56427	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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 15.1

Standard Rate IGS
Firm Industrial Gas Service

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	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: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 15.1

Standard Rate IGS
Firm Industrial Gas Service

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff. T

Off-Peak Pricing Provision:
The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by $0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

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

Gas Line Tracker	Sheet No. 84	T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Franchise Fee and Local Tax	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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 20

Standard Rate — AAGS — As-Available Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rate schedule is designed to make available to commercial and industrial customers quantities of natural gas that Company may from time to time have available for sale without impairment of service to customers served under other higher priority rate schedules, and which can be supplied from Company's existing distribution system, subject to the special conditions hereinafter set forth.

This rate shall not be available for gas loads which are predominantly space heating in character. In order to ensure that this rate schedule shall not be available for loads which are predominantly space heating in character and which do not consume substantial quantities of gas throughout the year, customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual Delivery Point.

Customers served under Rate G-6 and Rate G-7 as of the first effective date of this Rate AAGS shall have the right to elect service under Rate AAGS, Rate CGS, or Rate IGS. Such Customers that elect to transfer from either Rate G-6 or Rate G-7 to service under Rate AAGS may do so without complying with the requirement set forth above that customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual Delivery Point. Customers not electing service under either Rate CGS or Rate IGS shall receive service hereunder upon the first effective date hereof, irrespective of the November 1 start-date set forth in "Contract-Term" below.

COMPANY NOT OBLIGATED TO CONTINUE SERVICE
Company shall have the right to discontinue the supply of natural gas wholly or in part for such period or periods as, in the sole judgment of Company, may be necessary or advisable to enable it to supply the full gas requirements of its customers served under higher priority rate schedules. Nothing herein shall prevent Company from expanding its obligations under such other rate schedules. Company may decline to accept any additional contracts for service hereunder.

CONTRACT TERM
Customers served under Rate AAGS shall enter a written contract with Company more fully described in the Special Terms and Conditions of this rate schedule. The minimum contract term for service hereunder shall be for a period of at least one (1) year and shall commence on November 1 and be effective through the following October 31, and year to year thereafter, unless terminated by either Company or Customer upon prior written notice on or before the April 30 preceding the October 31 termination date.

Any customer served under Rate CGS or Rate IGS shall provide notice to Company by April 30 of its request for service to be effective commencing on the following November 1.

Date of Issue: August 6, 2010
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 20

Standard Rate — AAGS — As-Available Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rate schedule is designed to make available to commercial and industrial customers quantities of natural gas that Company may from time to time have available for sale without impairment of service to customers served under other higher priority rate schedules, and which can be supplied from Company's existing distribution system, subject to the special conditions hereinafter set forth.

This rate shall not be available for gas loads which are predominantly space heating in character. In order to ensure that this rate schedule shall not be available for loads which are predominantly space heating in character and which do not consume substantial quantities of gas throughout the year, customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual Delivery Point.

Customers served under Rate G-6 and Rate G-7 as of the first effective date of this Rate AAGS shall have the right to elect service under Rate AAGS, Rate CGS, or Rate IGS. Such Customers that elect to transfer from either Rate G-6 or Rate G-7 to service under Rate AAGS may do so without complying with the requirement set forth above that customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual Delivery Point. Customers not electing service under either Rate CGS or Rate IGS shall receive service hereunder upon the first effective date hereof, irrespective of the November 1 start-date set forth in "Contract-Term" below.

COMPANY NOT OBLIGATED TO CONTINUE SERVICE
Company shall have the right to discontinue the supply of natural gas wholly or in part for such period or periods as, in the sole judgment of Company, may be necessary or advisable to enable it to supply the full gas requirements of its customers served under higher priority rate schedules. Nothing herein shall prevent Company from expanding its obligations under such other rate schedules. Company may decline to accept any additional contracts for service hereunder.

CONTRACT TERM
Customers served under Rate AAGS shall enter a written contract with Company more fully described in the Special Terms and Conditions of this rate schedule. The minimum contract term for service hereunder shall be for a period of at least one (1) year and shall commence on November 1 and be effective through the following October 31, and year to year thereafter, unless terminated by either Company or Customer upon prior written notice on or before the April 30 preceding the October 31 termination date.

Any customer served under Rate CGS or Rate IGS shall provide notice to Company by April 30 of its request for service to be effective commencing on the following November 1.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Seventh Revision of Original Sheet No. 20.1
Canceling P.S.C. Gas No. 8, Sixth Revision of Original Sheet No. 20.1

STANDARD RATE SCHEDULE AAGS
As-Available Gas Service

RATE
Basic Service Charge:
$275.00 per delivery point per month

Plus a Charge Per Mcf

Distribution Cost Component	$ 0.5252
Gas Supply Cost Component	$ 3.4904
Total Charge Per Mcf	$ 4.0156

The "Gas Supply Cost Component" as shown above is the cost per Mcf determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet Nos. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

PENALTY FOR FAILURE TO INTERRUPT
Company shall have the right to interrupt sales service under this rate schedule upon eighteen (18) hours' prior notice. Provision of oral notice by telephone to Customer shall be deemed proper notice of interruption of service under this rate schedule.

In addition to the charges set forth above, if the Customer fails to discontinue the consumption of natural gas at its facility at the conclusion of the eighteen- (18-) hour notice period, Company may charge the Customer the following penalty for each Mcf used during the period of interruption in addition to any other remedy available to Company, including, but not limited to, immediate termination of service under this rate schedule, irrespective of the provisions set forth on "Contract Term", and immediate transfer by Company to either Rate CGS or Rate IGS, as applicable.

Customer shall be charged a per Mcf penalty charge equal to $15.00 plus the mid-point price posted in "*Gas Daily*" for Dominion–South Point on the day to which such interruption of service is applicable, plus any other charges under this rate schedule for such unauthorized usage by Customer that occurs following the conclusion of the eighteen- (18-) hour notice of interruption by Company to Customer.

If Customer is delivering quantities of gas to Company pursuant to Rate TS during such period of interruption, the charge described in the immediately preceding paragraph shall be applicable only to those quantities used by customer in excess of those being delivered by Customer to Company.

Date of Issue: April 26, 2012
Date Effective: May 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00125 dated April 24, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 20.1

STANDARD RATE SCHEDULE AAGS
As-Available Gas Service

RATE
Basic Service Charge:
$275.00 per delivery point per month

Plus a Charge Per Mcf

Distribution Cost Component	$ 0.6117	I
Gas Supply Cost Component	$ 3.4904	
Total Charge Per Mcf	$ 4.1021	I

The "Gas Supply Cost Component" as shown above is the cost per Mcf determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet Nos. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

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

Gas Line Tracker	Sheet No. 84	T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

PENALTY FOR FAILURE TO INTERRUPT
Company shall have the right to interrupt sales service under this rate schedule upon eighteen (18) hours' prior notice. Provision of oral notice by telephone to Customer shall be deemed proper notice of interruption of service under this rate schedule.

In addition to the charges set forth above, if the Customer fails to discontinue the consumption of natural gas at its facility at the conclusion of the eighteen- (18-) hour notice period, Company may charge the Customer the following penalty for each Mcf used during the period of interruption in addition to any other remedy available to Company, including, but not limited to, immediate termination of service under this rate schedule, irrespective of the provisions set forth on "Contract Term", and immediate transfer by Company to either Rate CGS or Rate IGS, as applicable.

Customer shall be charged a per Mcf penalty charge equal to $15.00 plus the mid-point price posted in "*Platts Gas Daily*" for Dominion–South Point on the day to which such interruption of service is applicable, plus any other charges under this rate schedule for such unauthorized usage by Customer that occurs following the conclusion of the eighteen- (18-) hour notice of interruption by Company to Customer. T

If Customer is delivering quantities of gas to Company pursuant to Rider TS during such period of interruption, the charge described in the immediately preceding paragraph shall be applicable only to those quantities used by customer in excess of those being delivered by Customer to Company. 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 20.2

Standard Rate | AAGS | As-Available Gas Service

Company shall not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of this rate schedule. Payment of penalty charges hereunder shall not be considered an exclusive remedy for failure to comply with the notice of interruption, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

SPECIAL TERMS AND CONDITIONS

1. Service shall be supplied hereunder only at such times and in such volumes as Company, in its sole judgment, determines that gas is available for such service without impairment of service supplied under other rate schedules.

2. Each customer served hereunder shall be required to enter into a written contract specifying, among other things, realistic monthly requirements for gas under this rate schedule. Such volumes shall be used as the basis for apportionment of gas when the total customer requirements exceed the quantity of gas available for service hereunder.

3. The customer shall contract under this rate schedule for a specified quantity of gas stated in terms of maximum required deliveries in Mcf per day. On no day shall Company be obligated to supply gas in excess of such contract quantity. In no case will Company be obligated to supply gas to Customer at greater volumes and greater rates of flow than those historically delivered by Company to Customer.

4. Customer shall discontinue taking service upon applicable notice by Company to do so.

5. No gas service whatsoever to Customer's equipment or process served hereunder shall be supplied or permitted to be taken under any other of Company's gas rate schedules during periods of interruption.

6. Upon commencement of service hereunder, Customer shall be required to certify that Customer's alternate fuel facilities are operational and alternate fuel is on site and capable of use. Company may, at its discretion, verify such certification through physical inspection of Customer's facility. In the event that Customer does not have alternate fuel facilities, Customer shall certify that the processes which utilize gas delivered hereunder are capable of complete discontinuance of natural gas use. Company may request Customer to verify either of the foregoing alternatives on an annual basis on or before October 1 of each year. Failure of Customer to annually certify either of the above alternatives shall result, in the sole discretion of Company, in immediate termination of service under this rate schedule and the immediate transfer to the appropriate firm sales rate schedule, either Rate CGS or Rate IGS.

7. Service hereunder must be supplied through a separate meter and physically isolated from any other service provided by Company under other rate schedules.

8. Company shall not be obligated to install or construct any facilities (other than necessary meters and regulators) in order to provide service hereunder.

Date of Issue: August 6, 2010
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 20.2

Standard Rate | AAGS | As-Available Gas Service

Company shall not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of this rate schedule. Payment of penalty charges hereunder shall not be considered an exclusive remedy for failure to comply with the notice of interruption, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

SPECIAL TERMS AND CONDITIONS

1. Service shall be supplied hereunder only at such times and in such volumes as Company, in its sole judgment, determines that gas is available for such service without impairment of service supplied under other rate schedules.

2. Each customer served hereunder shall be required to enter into a written contract specifying, among other things, realistic monthly requirements for gas under this rate schedule. Such volumes shall be used as the basis for apportionment of gas when the total customer requirements exceed the quantity of gas available for service hereunder.

3. The customer shall contract under this rate schedule for a specified quantity of gas stated in terms of maximum required deliveries in Mcf per day. On no day shall Company be obligated to supply gas in excess of such contract quantity. In no case will Company be obligated to supply gas to Customer at greater volumes and greater rates of flow than those historically delivered by Company to Customer.

4. Customer shall discontinue taking service upon applicable notice by Company to do so.

5. No gas service whatsoever to Customer's equipment or process served hereunder shall be supplied or permitted to be taken under any other of Company's gas rate schedules during periods of interruption.

6. Upon commencement of service hereunder, Customer shall be required to certify that Customer's alternate fuel facilities are operational and alternate fuel is on site and capable of use. Company may, at its discretion, verify such certification through physical inspection of Customer's facility. In the event that Customer does not have alternate fuel facilities, Customer shall certify that the processes which utilize gas delivered hereunder are capable of complete discontinuance of natural gas use. Company may request Customer to verify either of the foregoing alternatives on an annual basis on or before October 1 of each year. Failure of Customer to annually certify either of the above alternatives shall result, in the sole discretion of Company, in immediate termination of service under this rate schedule and the immediate transfer to the appropriate firm sales rate schedule, either Rate CGS or Rate IGS.

7. Service hereunder must be supplied through a separate meter and physically isolated from any other service provided by Company under other rate schedules.

8. Company shall not be obligated to install or construct any facilities (other than necessary meters and regulators) in order to provide service hereunder.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

9. Any Customer contracting for service hereunder, other than a Customer transferring from either Rate G-6 or Rate G-7 as stipulated above, may be required, in the sole discretion of Company, either prior to electing service hereunder or at anytime thereafter, to have appropriate remote metering devices. The remote metering devices allow Company to monitor the Customer's usage and determine compliance with notice of interruption of service hereunder. The Customer shall be responsible for the cost of the remote metering equipment and the cost of its installation.

   Any Customer required to have remote metering as described above shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

   Any Customer required to have remote metering shall be responsible for providing the necessary and adequate electric and telephone service to provide this metering within thirty (30) days of Company's notice to Customer that such remote metering shall be required. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide such remote metering.

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.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof.

9. Any Customer contracting for service hereunder, other than a Customer transferring from either Rate G-6 or Rate G-7 as stipulated above, may be required, in the sole discretion of Company, either prior to electing service hereunder or at anytime thereafter, to have appropriate remote metering devices. The remote metering devices allow Company to monitor the Customer's usage and determine compliance with notice of interruption of service hereunder. The Customer shall be responsible for the cost of the remote metering equipment and the cost of its installation.

   Any Customer required to have remote metering as described above shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

   Any Customer required to have remote metering shall be responsible for providing the necessary and adequate electric and telephone service to provide this metering within thirty (30) days of Company's notice to Customer that such remote metering shall be required. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide such remote metering.

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.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof.

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 30

Standard Rate FT

Firm Transportation Service (Non-Standby)

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to commercial and industrial customers who consume at least 50 Mcf each day at each individual Delivery Point, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's Pipeline Transporter, and have requested Company to utilize its system to transport, by displacement, such customer-owned gas to Customer's place of utilization. Customers electing to transfer from another service shall notify Company on or before March 31 and execute a contract by April 30 in order to begin receiving service hereunder beginning November 1 of that same year. Any such transportation service hereunder shall be conditioned on Company being granted a reduction in billing demands by its Pipeline Transporter corresponding to the Customer's applicable transportation quantities.

Transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

CHARACTER OF SERVICE

Transportation service under this rate schedule shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter ("Receipt Point") to the Delivery Point at the Customer's place of utilization ("Delivery Point"), subject to paragraph 6 of the Special Conditions.

Company's sole obligation hereunder is to redeliver Customer's gas from the Receipt Point to the Delivery Point. Accordingly, Company has no obligation to deliver to the Customer a volume of gas, either daily or monthly, which differs from the volume delivered to Company at the Receipt Point.

Company will provide service to meet imbalances only on an as-available basis. For purposes used herein, "Imbalances" are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point. When Company can provide such service, the Utilization Charge for Daily Imbalances shall apply to daily imbalances in excess of ±10% of the delivered volume of gas as set forth herein. Company shall issue an Operational Flow Order as set forth herein during periods when service cannot be provided to meet daily imbalances.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, and any other charges set forth herein, the following charges shall apply.

Administration Charge: $230.00 per Delivery Point per month

Distribution Charge Per Mcf: $0.43

Date of Issue: August 6, 2010
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 30

Standard Rate FT

Firm Transportation Service (Transportation Only) T

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to existing commercial and industrial customers who consume at least 50 Mcf each day at each individual Delivery Point during each month of the twenty-four (24) months prior to the March 31 service request date, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's Pipeline Transporter, and have requested Company to utilize its system to transport, by displacement, such customer-owned gas to Customer's place of utilization. Customers electing to transfer from another service shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rate schedule shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30. T T T T

For new customers whose historical gas consumption is not available, Company will determine Customer's eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Any such transportation service hereunder shall be conditioned on Company being granted a reduction in billing demands by its Pipeline Transporter corresponding to the Customer's applicable transportation quantities.

Transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Service under this rate schedule shall not be available to customers with a Maximum Daily Quantity ("MDQ") in excess of 20,000 Mcf/day. In the event that Customer's MDQ exceeds 20,000 Mcf/day, Company may terminate service under this rate schedule upon thirty (30) days prior written notice. Additionally, customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer's MDQ, are not eligible for service under this rate schedule. T

CHARACTER OF SERVICE

Transportation service under this rate schedule shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter ("Receipt Point") to the Delivery Point at the Customer's place of utilization ("Delivery Point"), subject to paragraph 6 of the Special Terms and Conditions. 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, Louisville, Kentucky

Standard Rate FT

Firm Transportation Service (Non-Standby)

ADJUSTMENT CLAUSES

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	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.

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.

IMBALANCES

Company will calculate on a daily and monthly basis the Customer's imbalance resulting from the difference between the metered usage of the Customer and the volumes that the Customer has delivered into Company's system. This will be calculated as follows:

Imbalance = Metered Usage - Delivered Volume

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volume}}$$

The term daily shall mean the period of twenty-four (24) consecutive hours beginning at 10:00 a.m., Eastern Clock Time.

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from Customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lowest daily mid-point price posted in "*Gas Daily*" for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Standard Rate FT

Firm Transportation Service (Transportation Only) T

Due to the physical configuration of Company's system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company's sole obligation hereunder is to redeliver Customer's gas from the Receipt Point to the Delivery Point. Accordingly, Company has no obligation to deliver to the Customer a volume of gas, either daily or monthly, which differs from the volume delivered to Company at the Receipt Point.

Company will provide service to meet imbalances only on an as-available basis. For purposes used herein, "Imbalances" are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point. When Company can provide such service, the Utilization Charge for Daily Imbalances shall apply to daily imbalances in excess of ±5% of the delivered volume of gas as set forth herein. Company shall issue an Operational Flow Order as set forth herein during periods when service cannot be provided to meet daily imbalances.

Customers served under this rate may elect to become a member of an FT Pool pursuant to Rider PS-FT.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, and any other charges set forth herein, the following charges shall apply.

Administrative Charge: $600.00 per Delivery Point per month T/I

Distribution Charge Per Mcf: $0.43 T

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rate FT. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rate FT in order to recover from (or refund to) transferring sales customers any under- or over-collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly Gas Supply Clause filings.

For customers electing service under Rate FT effective November 1, 2010, the Gas Cost True-Up Charge shall be:

($0.1593) per Mcf for Bills Rendered On and After May 1, 2012

For customers electing service under Rate FT effective November 1, 2011, the Gas Cost True-Up Charge shall be:

($0.1709) per Mcf for Bills Rendered On and After May 1, 2012

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 30.2

Standard Rate FT

Firm Transportation Service (Non-Standby)

When Total Net Negative Imbalance Percentage is:	The following percentage shall be multiplied by the above-referenced "*Gas Daily*" price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall be billed for the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the highest daily mid-point price posted in "*Gas Daily*" for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-referenced "*Gas Daily*" price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	110%
>10% to ≤15%	120%
>15% to ≤20%	130%
>20%	140%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a Customer with a monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the Customer's monthly bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

VARIATIONS IN MMBTU CONTENT

Changes in billings of the "cash-out" provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

UTILIZATION CHARGE FOR DAILY IMBALANCES

Should an imbalance exceed ±10% of the delivered volume of gas on any day when an Operational Flow Order (as described below) has not been issued, then Company shall charge the Utilization Charge for Daily Imbalances times the recorded imbalance greater than ±10% of the delivered volume of gas for each daily occurrence. The Utilization Charge for Daily Imbalances is the sum of the following:

Date of Issue: August 6, 2010
Date Effective: November 1, 2000
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 30.2

Standard Rate FT

Firm Transportation Service (Transportation Only) T

Minimum Daily Threshold Requirement and Charge: When Customer's daily usage falls below the Minimum Daily Threshold Requirement, Customer will be charged a Minimum Daily Threshold Charge equal to the difference between the Minimum Daily Threshold Requirement and the Customer's actual consumption in Mcf for that day multiplied by the Distribution Charge hereunder. The Minimum Daily Threshold Requirement is equal to the minimum daily volume of 50 Mcf. Such Minimum Daily Threshold Charge shall be accumulated for each day of the applicable month and billed during that month in accordance with the following formula: T

Minimum Daily Threshold Charge =

(Minimum Daily Threshold minus Customer Usage on Given Day) times the Distribution Charge

Such daily amount shall be accumulated for each day of the month and the total will be applied to Customer's bill.

Payment of the Minimum Daily Threshold Charge is not a remedy for Customer's failure to meet the Minimum Daily Threshold Requirement for service under Rate FT. In the event that Customer does not meet the Minimum Daily Threshold Requirement for one-hundred twenty (120) days during a given Contract Year, service to Customer under Rate FT may be discontinued by Company. Customer will receive thirty (30) days prior written notice that Customer will be removed from Rate FT and returned to firm sales service under either Rate CGS or IGS as applicable.

Other: In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then Customer shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

ADJUSTMENT CLAUSES

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	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.

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.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Sixth Revision of Original Sheet No. 30.3
Canceling P.S.C. Gas No. 8, Fifth Revision of Original Sheet No. 30.3

Standard Rate FT

Firm Transportation Service (Non-Standby)

Daily Demand Charge:	$0.1722 per Mcf
Daily Storage Charge:	$0.1833
Utilization Charge for Daily Imbalances:	$0.3555 per Mcf

Note: The Daily Demand Charge may change with each filing of the GSCC.

These charges are in addition to any other charges set forth herein. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed ±10% of the delivered volume. Company shall not have an obligation to provide balancing service for any volumes of gas hereunder.

OPERATIONAL FLOW ORDERS

Company shall have the right to issue an Operational Flow Order ("OFO") which will require actions by Customer to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system required to maintain system reliability. Customer shall be responsible for complying with the directives contained in the OFO.

Upon issuance of an OFO, Company will direct Customer to comply with one of the following conditions: (a) Customer must take delivery of an amount of natural gas from Company that is no more than the daily amount being delivered by the Pipeline Transporter to Company for Customer; or (b) Customer must take delivery of an amount of natural gas from Company that is no less than the daily amount being delivered by the Pipeline Transporter to Company for Customer. Provision of oral notice by telephone to Customer shall be deemed as proper notice of an OFO. Customer shall respond to an OFO by either adjusting its deliveries to Company's system or its consumption at its facility.

All volumes taken by Customer in excess of volumes delivered by Pipeline Transporter to Company for Customer in violation of the above "condition (a)" OFO shall constitute an unauthorized receipt by Customer from Company. All volumes taken by Customer less than volumes delivered by Pipeline Transporter to Company for Customer in violation of "condition (b)" OFO shall constitute an unauthorized delivery by Customer to Company. Customer shall be charged a per Mcf charge equal to $15.00 plus the mid-point price posted in *"Gas Daily"* for Dominion South Point on the day for which the OFO was violated, plus any other charges under this rate schedule for such unauthorized receipts or deliveries that occur twenty-four (24) hours after notice of the OFO is provided to the Customer or that fall outside the ±10 percent imbalance tolerance regardless of the notice.

Company will not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of an OFO. Payment of charges hereunder shall not be considered an exclusive remedy for failure to comply with the OFO, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

Date of Issue: January 26, 2012
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Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00523 dated January 24, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 30.3

Standard Rate FT

Firm Transportation Service (Transportation Only) T

IMBALANCES

Company will calculate on a daily and monthly basis the Customer's imbalance resulting from the difference between the metered usage of the Customer and the volumes that the Customer has delivered into Company's system. This will be calculated as follows: T

Imbalance = Metered Usage - Delivered Volume

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volume}}$$

The term "day" or "daily" shall mean the period of twenty-four (24) consecutive hours beginning at 10:00 a.m., Eastern Clock Time.

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from Customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lowest daily mid-point price posted in *"Platts Gas Daily"* for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

When Total Net Negative Imbalance Percentage is:	The following percentage shall be multiplied by the above-referenced *"Platts Gas Daily"* price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall be billed for the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the highest daily mid-point price posted in *"Platts Gas Daily"* for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

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

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 30.4

Standard Rate FT

Firm Transportation Service (Non-Standby)

OPTIONAL SALES AND PURCHASE TRANSACTION

Customer may agree to sell its natural gas supplies to Company, and Company may agree to purchase natural gas supplies from Customer under a written contract setting forth specific arrangements of the transaction. If Company purchases natural gas from Customer, such gas will not be redelivered to Customer, and Customer shall discontinue or otherwise interrupt the usage of such natural gas.

RETURN TO FIRM SALES SERVICE

Return to firm sales service is contingent upon the ability of Company to secure the appropriate quantities of gas supply and transportation capacity with Company's Pipeline Transporter, as determined solely by Company.

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rate schedule. The remote metering devices will allow Company to monitor the Customer's usage on a daily basis and bill the Customer.

The Customer shall be responsible for the cost of this remote metering equipment and the cost of its installation.

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide remote metering by October 1st of the year that the Customer's Rate FT service becomes effective. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be transported by Company for Customer, Delivery Points, methods of metering, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

2. At least ten days prior to the beginning of each month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for Customer's account. Customer shall give Company at least twenty-four hours written notice of any subsequent changes to scheduled deliveries of natural gas flow. Company will not be obligated to utilize its underground storage capacity for purposes of this service.

3. In no case will Company be obligated to transport greater quantities hereunder than those specified in the written contract between Customer and Company.

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 30.4

Standard Rate FT

Firm Transportation Service (Transportation Only) T

T

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-referenced "*Platts Gas Daily*" price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	110%
>10% to ≤15%	120%
>15% to ≤20%	130%
>20%	140%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a Customer with a monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the Customer's monthly bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

UTILIZATION CHARGE FOR DAILY IMBALANCES

Should an imbalance exceed ±5% of the delivered volume of gas on any day when an Operational Flow Order (as described below) has not been issued, then Company shall charge the Utilization Charge for Daily Imbalances times the recorded imbalance greater than ±5% of the delivered volume of gas for each daily occurrence. The Utilization Charge for Daily Imbalances is the sum of the following:

Daily Demand Charge:	$0.1722 per Mcf
Daily Storage Charge:	$0.1833
Utilization Charge for Daily Imbalances:	$0.3555 per Mcf

Note: The Daily Demand Charge may change with each filing of the GSCC.

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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, Louisville, Kentucky

Standard Rate FT

Firm Transportation Service (Non-Standby)

4. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.
5. All volumes of natural gas transported hereunder shall be of the same quality and meet the same specifications as that delivered to Company by its Pipeline Transporter.
6. Company will have the right to curtail or interrupt the transportation or delivery of gas to any customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.
7. Should Customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will not be obligated hereunder to provide standby quantities for purposes of supplying such Customer requirements.
8. Company shall not be required to render service under this rate schedule to any customer that fails to comply with any and all of the terms and conditions of this rate schedule.

TERMS AND CONDITIONS

Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

Standard Rate FT

Firm Transportation Service (Transportation Only) T

These charges are in addition to any other charges set forth herein. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed ±5% of the delivered volume. Company shall not have an obligation to provide balancing service for any volumes of gas hereunder. T

OPERATIONAL FLOW ORDERS

Company shall have the right to issue an Operational Flow Order ("OFO") which will require actions by Customer to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. Customer shall be responsible for complying with the directives contained in the OFO.

Notice of an OFO shall be provided to Customer at least twenty-four (24) hours prior to the beginning of the gas day for which the OFO is in effect. Customer shall respond to an OFO by adjusting its deliveries to Company's system as directed in the OFO within the specified timeframe. If Customer is a member of an FT Pool, it is the responsibility of the FT Pool Manager, not Company, to convey OFOs to Customers in its FT Pool.

Upon issuance of an OFO, Company will direct Customer to comply with one of the following conditions: (a) Customer must take delivery of an amount of natural gas from Company that is no more than the daily amount being delivered by the Pipeline Transporter to Company for Customer; or (b) Customer must take delivery of an amount of natural gas from Company that is no less than the daily amount being delivered by the Pipeline Transporter to Company for Customer. Customer shall respond to an OFO by either adjusting its deliveries to Company's system or its consumption at its facility. All volumes taken by Customer in excess of volumes delivered by Pipeline Transporter to Company for Customer in violation of the above "condition (a)" OFO shall constitute an unauthorized receipt by Customer from Company. All volumes taken by Customer less than volumes delivered by Pipeline Transporter to Company for Customer in violation of "condition (b)" OFO shall constitute an unauthorized delivery by Customer to Company. Customer shall be subject to the OFO Charge on the day for which the OFO was violated, plus the applicable UCDI charges and any other charges under this rate schedule for such unauthorized receipts or deliveries that occur

Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT.

The OFO Charge shall be equal to $15.00 plus the mid-point price posted in *"Platts Gas Daily"* for Dominion South Point per Mcf on the day for which the OFO was violated, plus any other charges under this rate schedule.

Company will not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of an OFO. Payment of OFO Charges hereunder shall not be considered an exclusive remedy for failure to comply with the OFO, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

The proposed LG&E Firm Transportation Service Rate FT is contained on eight pages instead of the current six pages.

OPTIONAL SALES AND PURCHASE TRANSACTION T

Customer may agree to sell its natural gas supplies to Company, and Company may agree to purchase natural gas supplies from Customer pursuant to Company's Curtailment Rules. If Company purchases natural gas from Customer, such gas will not be redelivered to Customer, and Customer shall discontinue or otherwise interrupt the usage of such natural gas.

RETURN TO FIRM SALES SERVICE

Return to firm sales service is contingent upon the ability of Company to secure the appropriate quantities of gas supply and transportation capacity with Company's Pipeline Transporter, as determined solely by Company.

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rate schedule. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

The Customer shall be responsible for the cost of this remote metering equipment and the cost of its installation.

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide remote metering by October 1 of the year that the Customer's Rate FT service becomes effective. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be transported by Company for Customer, Delivery Points, timing of receipts and deliveries of gas by Company, and any other matters relating to individual Customer circumstances.

2. As further described below, Customer shall specify to Company the daily volume of gas required by Customer. Such volume shall be stated in Mcf/day and converted to MMBtu/day using a standard conversion factor as may be specified by Company from time to time. At least ten (10) days prior to the beginning of each month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's

The proposed LG&E Firm Transportation Service Rate FT is contained on eight pages instead of the current six pages.

Standard Rate FT
Firm Transportation Service (Transportation Only) T

SPECIAL TERMS AND CONDITIONS (continued) T

system for Customer's account. Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by Customer to Company no later than 8:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from Customer daily nominations, or changes thereto, that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company. Company will not be obligated to utilize its underground storage capacity for purposes of this service.

3. In no case will Company be obligated to deliver gas, including both gas transported and gas sold, to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be referred to as the Maximum Daily Quantity ("MDQ"). The MDQ is the maximum daily volume of gas, as determined by Company, based on Customer's historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine the MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis.

4. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.

5. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

6. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

7. Should Customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will not be obligated hereunder to provide standby quantities for purposes of supplying such Customer requirements.

8. Company shall not be required to render service under this rate schedule to any Customer that fails to comply with any and all of the terms and conditions of this rate schedule.

TERMS AND CONDITIONS

Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 35

Standard Rate DGGS

Distributed Generation Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to customer-owned electric generation facilities except (i) when such natural gas is limited to the production of electricity for Customer's own use during emergency situations during which Customer's normal supply of electricity is not otherwise available, and (ii) when such electric generation facilities have a total connected load of less than 2,000 cubic feet per hour. Natural gas purchased for electric generation facilities with a total connected load of 2,000 or more cubic feet per hour, or purchased to generate electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electrical supplies during emergency situations shall be subject to this tariff. Additionally, service under this Standard Rate DGGS shall be applicable only to electric generation facilities described above and installed and operating on and after ninety (90) days after the effective date of Rate DGGS (and therefore not eligible for service under Standard Rates CGS or IGS) by commercial and industrial customers.

Service hereunder shall be at a single delivery (custody transfer) point and where distribution mains are adjacent to the premises to be served. Gas sales service provided hereunder shall be metered and billed separately from gas service provided under any other rate schedule.

Sales service hereunder shall be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other customers. Company may decline to accept customers under this rate schedule with a connected load of more than 8,000 cubic feet per hour. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this rate schedule.

If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, such residential customer shall be served under Rate DGGS.

CHARACTER OF SERVICE
Gas sales service under this rate schedule shall be considered firm.

RATE
In addition to any other charges set forth herein, the following charges shall apply.

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 30.00 per delivery point per month
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$170.00 per delivery point per month

Date of Issue: August 6, 2010
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Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 35

Standard Rate DGGS

Distributed Generation Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to customer-owned electric generation facilities except (i) when such natural gas is limited to the production of electricity for Customer's own use during emergency situations during which Customer's normal supply of electricity is not otherwise available, and (ii) when such electric generation facilities have a total connected load of less than 2,000 cubic feet per hour. Natural gas purchased for electric generation facilities with a total connected load of 2,000 or more cubic feet per hour, or purchased to generate electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electrical supplies during emergency situations shall be subject to this tariff. Additionally, service under this Standard Rate DGGS shall be applicable only to electric generation facilities described above and installed and operating on and after ninety (90) days after August 1, 2010, (and therefore not eligible for service under Standard Rates T CGS or IGS) by commercial and industrial customers.

Service hereunder shall be at a single delivery (custody transfer) point and where distribution mains are adjacent to the premises to be served. Gas sales service provided hereunder shall be metered and billed separately from gas service provided under any other rate schedule.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of T
2,000 cubic feet per hour under Rate DGGS shall not be permitted. T

Sales service hereunder shall be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other customers. Company may decline to accept customers under this rate schedule with a connected load of more than 8,000 cubic feet per hour. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this rate schedule.

If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, such residential customer shall be served under Rate DGGS.

CHARACTER OF SERVICE
Gas sales service under this rate schedule shall be considered firm.

RATE
In addition to any other charges set forth herein, the following charges shall apply.

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 35.00 per delivery point per month	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$175.00 per delivery point per month	I

Date of Issue: June 29, 2012
Date Effective: August 1, 2010, 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Seventh Revision of Original Sheet No. 35.1
Canceling P.S.C. Gas No. 8, Sixth Revision of Original Sheet No. 35.1

Standard Rate — DGGS
Distributed Generation Gas Service

Demand Charge per 100 cubic feet of Monthly Billing Demand:	$1.0110
Plus a Charge Per 100 Cubic Feet:	
Distribution Cost Component	$0.02744
Gas Supply Cost Component	0.34904
Total Charge Per 100 Cubic Feet	$0.37648

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

The total monthly minimum bill shall be the sum of the minimum monthly Demand Charge and the Monthly Basic Service Charge.

In no case shall Company be obligated to deliver greater volumes hereunder than those specified in the written contract between Customer and Company. Payment of any and all charges hereunder shall not be considered an exclusive remedy for takes in excess of the maximum daily quantity ("MDQ"), nor shall the payment of such charges be considered a substitute for any other remedy (including, but not limited to, physical discontinuance or suspension of service hereunder) available to Company.

ADJUSTMENT CLAUSES

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

Franchise Fee and Local Tax	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.

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.

Date of Issue: April 26, 2012
Date Effective: May 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00125 dated April 24, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 35.1

Standard Rate — DGGS
Distributed Generation Gas Service

Demand Charge per 100 cubic feet of Monthly Billing Demand:	$1.0900	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$0.03222	I
Gas Supply Cost Component	0.34904	
Total Charge Per 100 Cubic Feet	$0.38126	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

The total monthly minimum bill shall be the sum of the minimum monthly Demand Charge and the Monthly Basic Service Charge.

In no case shall Company be obligated to deliver greater volumes hereunder than those specified in the written contract between Customer and Company. Payment of any and all charges hereunder shall not be considered an exclusive remedy for takes in excess of the maximum daily quantity ("MDQ"), nor shall the payment of such charges be considered a substitute for any other remedy (including, but not limited to, physical discontinuance or suspension of service hereunder) available to Company.

ADJUSTMENT CLAUSES

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

Gas Line Tracker	Sheet No. 84	T
Franchise Fee and Local Tax	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.

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.

Date of Issue: June 29, 2012
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Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 35.2

Standard Rate DGGS
Distributed Generation Gas Service

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be sold by Company to Customer, and any other matters relating to individual customer circumstances.

2. The minimum contract term for service hereunder shall be for a period not less than five (5) years commencing from the effective date thereof.

3. Such written contract shall specify the minimum delivery pressure, the maximum hourly rate ("MHR"), and the maximum daily quantity ("MDQ"). The MHR is the maximum hourly gas load in 100 cubic feet that the Customer's installation will require when operating at full capacity. The MDQ shall be twenty-four (24) times the MHR. The MDQ is the Monthly Billing Demand and shall not be less than 10 (ten) Ccf.

4. In no case shall Company be obligated to make deliveries hereunder at a pressure greater than thirty (30) psig, or the prevailing line pressure, whichever is less.

5. Increases in the MDQ may be requested annually by Customer. Customer may request Company to increase the MDQ at least ninety (90) days in advance of the anniversary date of the written contract. Such increases in the MDQ that are acceptable to Company in its sole discretion shall be effective on the anniversary date of the effective date of the written contract.

6. In the event that Company agrees to install any Company-owned facilities required to serve Customer, such facilities to be installed by Company shall be specified in the written contract and the cost of such facilities and installation thereof shall be paid by Customer to Company.

TERMS AND CONDITIONS

Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 35.2

Standard Rate DGGS
Distributed Generation Gas Service

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be sold by Company to Customer, and any other matters relating to individual customer circumstances.

2. The minimum contract term for service hereunder shall be for a period not less than five (5) years commencing from the effective date thereof.

3. Such written contract shall specify the minimum delivery pressure, the maximum hourly rate ("MHR"), and the maximum daily quantity ("MDQ"). The MHR is the maximum hourly gas load in 100 cubic feet that the Customer's installation will require when operating at full capacity. The MDQ shall be twenty-four (24) times the MHR. The MDQ is the Monthly Billing Demand and shall not be less than 480 (four hundred and eighty) Ccf. T

4. In no case shall Company be obligated to make deliveries hereunder at a pressure greater than thirty (30) psig, or the prevailing line pressure, whichever is less.

5. Increases in the MDQ may be requested annually by Customer. Customer may request Company to increase the MDQ at least ninety (90) days in advance of the anniversary date of the written contract. Such increases in the MDQ that are acceptable to Company in its sole discretion shall be effective on the anniversary date of the effective date of the written contract.

6. In the event that Company agrees to install any Company-owned facilities required to serve Customer, such facilities to be installed by Company shall be specified in the written contract and the cost of such facilities and installation thereof shall be paid by Customer to Company.

TERMS AND CONDITIONS

Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 45

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 (2) percent fast, the Customer will be charged $80.00 to cover the test and transportation costs.

DISCONNECT/RECONNECT SERVICE CHARGE
A charge of $29.00 will be made to cover disconnection and reconnection of gas 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. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $29.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection.

Customers under Gas Rates RGS, CGS and IGS may request and be granted temporary suspension of gas service. In the event of such temporary suspension, Company will make a charge of $29.00 to cover disconnection and reconnection of gas service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $29.00.

INSPECTION CHARGE
With respect to Customer's service line and house line inspections prior to initiation or resumption of gas service, Company will make two such inspections without charge. When more than two trips are necessary to complete the inspections at any one location, a charge of $135.00 will be made for each additional trip.

CHARGE FOR TEMPORARY AND SHORT TERM SERVICE
The customer shall pay the cost of all material, labor and expense incurred by Company in supplying gas service for any temporary or short term use, in addition to the regular rates for service without pro-rating of rate blocks or minimum charges for service of less than thirty days in a regular meter reading period.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 45

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 (2) percent fast, the Customer will be charged $90.00 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 gas service R
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. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. No charge R
will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection.

Customers under Gas Rates RGS, CGS and IGS may request and be granted temporary suspension of gas service. In the event of such temporary suspension, Company will make a charge of $28.00 to cover disconnection and reconnection of gas service, such charge to be R
made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. R

INSPECTION CHARGE
With respect to Customer's service line and house line inspections prior to initiation or resumption of gas service, Company will make two such inspections without charge. When more than two trips are necessary to complete the inspections at any one location, a charge of $150.00 will be made for each additional trip. I

CHARGE FOR TEMPORARY AND SHORT TERM SERVICE
The customer shall pay the cost of all material, labor and expense incurred by Company in supplying gas service for any temporary or short term use, in addition to the regular rates for service without pro-rating of rate blocks or minimum charges for service of less than thirty days in a regular meter reading period.

ADDITIONAL TRIP CHARGE T
Under Rate FT, Rider TS-2, and Rider GMPS, if the Company is required to make additional visits to the meter site due to the Company's inability to gain access to the meter location, or the necessary Communication Link (such as electric and telephone service) has not been properly installed by Customer, or the Customer's Communication Link is not working properly, the Company may charge the Customer for any additional trip to the site at a per-visit rate of $150.00.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Eighth Revision of Original Sheet No. 50
Canceling P.S.C. Gas No. 8, Seventh Revision of Original Sheet No. 50

Standard Rate Rider TS

Gas Transportation Service/Standby

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to commercial and industrial customers served under Rate CGS and Rate IGS who consume either (a) an average of at least 50 Mcf each day during the billing cycle at each individual Delivery Point, or (b) 50,000 Mcf annually at each individual Delivery Point. Also available to customers served under Rate AAGS who consume at least 50 Mcf each day during the billing cycle at each individual Delivery Point. Customer shall have purchased natural gas elsewhere, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. Any transportation service hereunder will be conditioned on Company being able to retain or secure adequate standby quantities of natural gas. In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

RATE
In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $153.00 per Delivery Point per month

	CGS	IGS	AAGS
Distribution Charge Per Mcf	$1.8722	$1.9022	$0.5252
Pipeline Supplier's Demand Component	0.8800	0.8800	0.8800
Total	$2.7522	$2.7822	$1.4052

The **"Distribution Charge"** applicable to Rate CGS and IGS monthly quantities in excess of 100 Mcf shall be reduced by $0.50 per Mcf during the seven off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component: Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's Gas Supply Clause.

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

Date of Issue: April 26, 2012
Date Effective: May 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00125 dated April 24, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 50

Standard Rate Rider TS

Gas Transportation Service/Standby

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to commercial and industrial customers served under Rate CGS and Rate IGS who consume either (a) an average of at least 50 Mcf each day during the billing cycle at each individual Delivery Point, or (b) 50,000 Mcf annually at each individual Delivery Point. Also available to customers served under Rate AAGS who consume at least 50 Mcf each day during the billing cycle at each individual Delivery Point. Customer shall have purchased natural gas elsewhere, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. Any transportation service hereunder will be conditioned on Company being able to retain or secure adequate standby quantities of natural gas. In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Rider TS shall continue to be effective for customers who have previously elected to transport under Rider TS as of the effective date hereof. However, service hereunder shall terminate on October 31, 2013, at which point Rider TS shall no longer be in effect. T T T

RATE
In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $592.00 per Delivery Point per month I

	CGS	IGS	AAGS	
Distribution Charge Per Mcf	$2.1142	$2.1523	$0.6117	I
Pipeline Supplier's Demand Component	0.8800	0.8800	0.8800	
Total	$2.9942	$3.0323	$1.4917	I

The **"Distribution Charge"** applicable to Rate CGS and IGS monthly quantities in excess of 100 Mcf shall be reduced by $0.50 per Mcf during the seven off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component: Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's Gas Supply Clause.

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 50.1

Standard Rate Rider TS
Gas Transportation Service/Standby

IMBALANCES

Company will calculate on a monthly basis the Customer's imbalance resulting from the difference between the metered usage of the Customer and the volumes that the Customer has delivered into Company's system. This will be calculated as follows:

Imbalance = Metered Usage - Delivered Volumes

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volumes}}$$

CASH-OUT PROVISION FOR POSITIVE MONTHLY IMBALANCES (STANDBY SERVICE)

Company will provide standby quantities of natural gas hereunder for purposes of supplying Customer's requirements should Customer be unable to obtain sufficient transportation volumes. Such standby service will be provided at the same rates and under the same terms and conditions as those set forth in Company's applicable rate schedule under which it sells gas to Customer.

CASH-OUT PROVISION FOR NEGATIVE MONTHLY IMBALANCES

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lowest daily mid-point price posted in "*Gas Daily*" for Dominion South Point during the month in which the negative imbalance occurred. The appropriate percentage shall be dependent on the Customer's monthly negative imbalance percentage to be applied as follows:

When Total Net Negative Balance Percentage is:	The following percentage shall be multiplied by the above referenced "*Gas Daily*" price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for negative imbalances that fall within each category. For example, a Customer with a

Date of Issue: August 6, 2010
Date Effective: November 1, 2000
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 50.1

Standard Rate Rider TS
Gas Transportation Service/Standby

IMBALANCES

Company will calculate on a monthly basis the Customer's imbalance resulting from the difference between the metered usage of the Customer and the volumes that the Customer has delivered into Company's system. This will be calculated as follows:

Imbalance = Metered Usage - Delivered Volumes

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volumes}}$$

CASH-OUT PROVISION FOR POSITIVE MONTHLY IMBALANCES (STANDBY SERVICE)

Company will provide standby quantities of natural gas hereunder for purposes of supplying Customer's requirements should Customer be unable to obtain sufficient transportation volumes. Such standby service will be provided at the same rates and under the same terms and conditions as those set forth in Company's applicable rate schedule under which it sells gas to Customer.

CASH-OUT PROVISION FOR NEGATIVE MONTHLY IMBALANCES

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lowest daily mid-point price posted in "*Platts Gas Daily*" for Dominion South Point during the month in which the negative T
imbalance occurred. The appropriate percentage shall be dependent on the Customer's monthly negative imbalance percentage to be applied as follows:

When Total Net Negative Balance Percentage is:	The following percentage shall be multiplied by the above referenced "*Platts Gas Daily*" price for Dominion South Point: T
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for negative imbalances that fall within each category. For example, a Customer with a negative monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of T
the imbalance and at the 5% to 10% price for 4% of the imbalance. 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, Louisville, Kentucky

negative monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the Customer's bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

Variations in MMBtu Content:
Changes in billings of the "cash-out" provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

SPECIAL TERMS AND CONDITIONS

1. Service under this rider shall be performed under a written contract between Customer and Company setting forth specific arrangements as to volumes to be transported by Company for Customer, points of delivery, methods of metering, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

2. At least ten days prior to the beginning of each month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for Customer's account. Customer shall give Company at least twenty-four (24) hours' prior notice of any subsequent changes to scheduled deliveries.

3. In no case will Company be obligated to supply gas to Customer, including both gas sold to Customer and gas transported hereunder, at greater volumes and greater rates of flow than those historically purchased by Customer from Company.

4. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.

5. All volumes of natural gas transported hereunder shall be of the same quality and meet the same specifications as that delivered to Company by its pipeline transporter.

6. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

7. Should Customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will provide standby quantities of natural gas to Customer as set forth in Customer's standard rate schedule CGS, IGS, or AAGS. In the event of an interruption of sales service to a Customer served under Rate AAGS, as provided for in that rate schedule, Company shall continue to deliver quantities of customer-owned natural gas in amounts equal to such quantities being delivered by pipeline transporter for Customer. During such periods of interruption, a Customer served under Rate AAGS shall not take quantities of natural gas in excess of those being delivered to Company on Customer's behalf. If Customer takes natural gas in excess of such quantities, Customer shall be subject to penalties in accordance with Company's Curtailment Rules.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

T

All such adjustments shall be shown and included on the Customer's bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

Variations in MMBtu Content:
Changes in billings of the "cash-out" provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

SPECIAL TERMS AND CONDITIONS

1. Service under this rider shall be performed under a written contract between Customer and Company setting forth specific arrangements as to volumes to be transported by Company for Customer, points of delivery, methods of metering, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

2. At least ten days prior to the beginning of each month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for Customer's account. Customer shall give Company at least twenty-four (24) hours' prior notice of any subsequent changes to scheduled deliveries.

3. In no case will Company be obligated to supply gas to Customer, including both gas sold to Customer and gas transported hereunder, at greater volumes and greater rates of flow than those historically purchased by Customer from Company.

4. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.

5. All volumes of natural gas transported hereunder shall be of the same quality and meet the same specifications as that delivered to Company by its pipeline transporter.

6. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

7. Should Customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will provide standby quantities of natural gas to Customer as set forth in Customer's standard rate schedule CGS, IGS, or AAGS. In the event of an interruption of sales service to a Customer served under Rate AAGS, as provided for in that rate schedule, Company shall continue to deliver quantities of customer-owned natural gas in amounts equal to such quantities being delivered by pipeline transporter for Customer. During such periods of interruption, a Customer served under Rate AAGS shall not take quantities of natural gas in excess of those being delivered to Company on Customer's behalf. If Customer takes natural gas in excess of such quantities, Customer shall be subject to penalties in accordance with Company's Curtailment Rules.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 50.3

Standard Rate Rider TS

Gas Transportation Service/Standby

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

Date of Issue: August 6, 2010
Date Effective: September 27, 2000
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 50.3

Standard Rate Rider TS

Gas Transportation Service/Standby

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

Date of Issue: June 29, 2012
Date Effective: September 27, 2000
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

The proposed LG&E Gas Transportation Service/Firm Balancing Service Rider TS-2 is not currently available.

Louisville Gas and Electric Company

Standard Rate Rider TS-2 N

Gas Transportation Service/Firm Balancing Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to existing commercial and industrial customers served under Rates AAGS, CGS, and IGS who consume at least 25,000 Mcf annually at each individual Delivery Point during the two (2) years ending with the March 31 service request date.

This rider is available for qualified customers electing to transport under Rider TS-2 beginning November 1, 2013.

Customers electing service under this rider shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rider shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30.

For new customers whose historical gas consumption is not available, Company will determine Customer's eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Customer shall have purchased natural gas elsewhere, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization

In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Service under this rider shall not be available to Customers with a Maximum Daily Quantity ("MDQ") in excess of 5,000 Mcf/day. In the event that Customer's MDQ exceeds 5,000 Mcf/day, Company may terminate service under this rider upon thirty (30) days prior written notice. Additionally, Customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer's MDQ, are not eligible for service under this rider.

CHARACTER OF SERVICE

Transportation service under this rider shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter ("Receipt Point") to the Delivery Point at the Customer's place of utilization ("Delivery Point"), subject to paragraph 6 of the Special 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, Louisville, Kentucky

The proposed LG&E Gas Transportation Service/Firm Balancing Service Rider TS-2 is not currently available.

Louisville Gas and Electric Company

Standard Rate Rider TS-2 N

Gas Transportation Service/Firm Balancing Service

Due to the physical configuration of Company's system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company will provide service to meet imbalances on a firm basis. For purposes used herein, "Imbalances" are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point.

Customers served under this rider must designate a TS-2 Pool Manager and become a member of a TS-2 Pool pursuant to Rider PS-TS-2.

Company shall issue an Action Alert as set forth in Rider PS-TS-2 when, in Company's sole discretion, such Action Alert is required to manage loads served under Rider TS-2. It is the responsibility of the TS-2 Pool Manager, not Company, to convey Action Alerts to Customers in the TS-2 Pool.

Any imbalances (over- or under-deliveries) incurred by TS-2 Pool Manager on behalf of Customer shall be resolved through the application of the cash-out mechanism incorporated in Rider PS-TS-2.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $600.00 per Delivery Point per month

	CGS	IGS	AAGS
Distribution Charge Per Mcf	$2.1142	$2.1523	$0.6117
Pipeline Supplier's Demand Component	0.8800	0.8800	0.8800
Total	$2.9942	$3.0323	$0.4917

The **"Distribution Charge"** applicable to Rate CGS and IGS monthly quantities in excess of 100 Mcf shall be reduced by $0.50 per Mcf during the seven off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component: Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's Gas Supply Clause.

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, Louisville, Kentucky

The proposed LG&E Gas Transportation Service/Firm Balancing Service Rider TS-2 is not currently available.

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder and not previously served under Rider TS. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rider TS-2. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rider TS-2 in order to recover from (or refund to) transferring sales customers any under- or over-collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly Gas Supply Clause filings.

For customers electing service under Rider TS-2 effective November 1, 2010, the Gas Cost True-Up Charge shall be:

($0.1593) per Mcf for Bills Rendered On and After May 1, 2012

For customers electing service under Rider TS-2 effective November 1, 2011, the Gas Cost True-Up Charge shall be:

($0.1709) per Mcf for Bills Rendered On and After May 1, 2012

Minimum Annual Threshold Requirement and Charge: When Customer's annual usage falls below the Minimum Annual Threshold Requirement, Customer will be charged a Minimum Annual Threshold Charge equal to the difference between the Minimum Annual Threshold Requirement of 25,000 Mcf and the Customer's actual consumption in Mcf during each Contract Year which difference shall be multiplied by the peak period Distribution Charge of the applicable sales rate schedule. Such Minimum Annual Threshold Charge shall be billed during the month following the close of the Contract Year in accordance with the following formula

Minimum Annual Threshold Charge =

(Minimum Annual Threshold minus Customer's Annual Usage) times the Peak Period Distribution Charge

Such amount shall be applied to Customer's November bill.

Payment of the Minimum Annual Threshold Charge is not a remedy for Customer's failure to meet the Minimum Annual Threshold Requirement for service under Rider TS-2. In the event that Customer does not meet the Minimum Annual Threshold Requirement for two (2) consecutive years (as determined for the 12 months ended October), service to Customer under this rider may be discontinued. Customer and its TS-2 Pool Manager will receive notice by December 1 that Customer will be removed from the TS-2 Pool and returned to firm sales service effective April 1 of the following year.

New customers qualifying for service hereunder and who begin service prior to the November 1 date specified above shall not be subject to any Minimum Annual Threshold Charge for service prior to the November 1 date immediately following the commencement of service hereunder.

Monthly Telemetry Charge: $300.00 per Delivery Point per month

The proposed LG&E Gas Transportation Service/Firm Balancing Service Rider TS-2 is not currently available.

ADJUSTMENT CLAUSES

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rider. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide remote metering by October 1 of the year that Customer's service under Rider TS-2 becomes effective. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

SPECIAL TERMS AND CONDITIONS

1. Service under this rider shall be performed under a written contract between Customer and Company setting forth specific arrangements as to volumes to be transported by Company for Customer, TS-2 Pool Manager designated by Customer, points of delivery, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

   Customer may appoint only one TS-2 Pool Manager for a given period. If Customer elects to change its TS-2 Pool Manager, Customer shall notify Company and execute and return the required documentation of its election to change its TS-2 Pool Manager at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective. Except as provided for in rider TS-2, no customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year. In appointing a TS-2 Pool Manager, Customer acknowledges that it has appointed the designated TS-2 Pool Manager to act as its limited agent in the performance of certain stated functions and to assume certain stated responsibilities with

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

The proposed LG&E Gas Transportation Service/Firm Balancing Service Rider TS-2 is not currently available.

SPECIAL TERMS AND CONDITIONS (continued)

regard to transportation under Rider TS-2, including the requesting and receiving of information, the scheduling of gas flows, and all related duties. Customer will continue to be responsible for any and all costs, fees, and other liabilities as the result of the actions or inactions of TS-2 Pool Manager as its limited agent. Customer shall indemnify, defend, and hold Company harmless from any costs (including, but not limited to, reasonable attorney fees), expenses, losses, or liabilities, incurred (a) as a result of Company's performance when relying upon the authority of the TS-2 Pool Manager, (b) as a result of Company's reliance upon Customer's representation that it has express authority to appoint said TS-2 Pool Manager as its limited agent, and (c) due to the Customer's or TS-2 Pool Manager's failure to strictly comply with the provisions of Rider TS-2 or Rider PS-TS-2.

2. In no case will Company be obligated to deliver gas to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be referred to as the Maximum Daily Quantity ("MDQ"). The MDQ is the maximum daily volume of gas, as determined by Company, based on Customer's historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine Customer's MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis.

3. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.

4. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

5. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

6. In the event of an interruption of service to a Customer served under Rate AAGS, as provided for in that rate schedule, Customer shall discontinue the use of natural gas as specified therein, be subject to the penalties set forth therein, and discontinue deliveries of natural has hereunder..

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 52

Standard Rate Rider — GMPS

Gas Meter Pulse Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to all commercial and industrial customers that request the Company to install a gas meter pulse generator which is a meter-related service not otherwise provided by the Company. This service is only available for customer metering sites using positive displacement meters, orifice meters, or ultrasonic metering technology, so long as the meter capacity is 3,000 cubic feet per hour or greater..

CHARACTER OF SERVICE

The service provided hereunder is a pulse generator (dry electrical contact closure) suitable for generating electrical pulses.

For customers not served under Rate Schedule FT, a separate pulse generator will be provided for each gas meter installed at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors may need to be applied by the Customer.

For customers served under Rate Schedule FT, a separate pulse generator will be totalized for gas meters at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors are applied to the volumes provided and need not be applied by the Customer.

The Customer shall be responsible for providing and maintaining the necessary and adequate electric and telephone service ("Communication Links") per the Company's specifications.

The Company will provide the pulse generator(s). Customer Installed Equipment is any equipment or wiring installed by the Customer, or someone other than Company acting on behalf of Customer, and could include, but would not be limited to, any device such as a data concentrator, totalizer, programmable logic controller, remote terminal unit, or similar equipment used for the purpose of collecting the pulse data. Customer is responsible for installation of wiring to the pulse generator(s) and is responsible for providing the wetting voltage necessary to generate electrical pulses, as well as all dielectric isolation fittings, surge protection and electrical barriers. The wetting voltage must be a regulated DC voltage of 30 volts or less and 10 mA or less, or as otherwise determined by the Company. If Customer Installed Equipment is located within fifteen (15) feet of any gas pipeline flanges, gas regulators, or gas pressure relief devices; or if gas meters are installed in an enclosed space, then Customer Installed Equipment must be installed in accordance with National Electrical Code Class 1 Division 2 requirements.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 52

Standard Rate Rider — GMPS

Gas Meter Pulse Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to all commercial and industrial customers that request the Company to install a gas meter pulse generator which is a meter-related service not otherwise provided by the Company. This service is only available for customer metering sites using positive displacement meters, orifice meters, or ultrasonic metering technology, so long as the meter capacity is 3,000 cubic feet per hour or greater..

CHARACTER OF SERVICE

The service provided hereunder is a pulse generator (dry electrical contact closure) suitable for generating electrical pulses.

For customers not served under Rate Schedule FT or Rider TS-2, a separate pulse generator will be provided for each gas meter installed at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors may need to be applied by the Customer. T

For customers served under Rate Schedule FT or Rider TS-2, a separate pulse generator will be totalized for gas meters at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors are applied to the volumes provided and need not be applied by the Customer. T

The Customer shall be responsible for providing and maintaining the necessary and adequate electric and telephone service ("Communication Links") per the Company's specifications.

The Company will provide the pulse generator(s). Customer Installed Equipment is any equipment or wiring installed by the Customer, or someone other than Company acting on behalf of Customer, and could include, but would not be limited to, any device such as a data concentrator, totalizer, programmable logic controller, remote terminal unit, or similar equipment used for the purpose of collecting the pulse data. Customer is responsible for installation of wiring to the pulse generator(s) and is responsible for providing the wetting voltage necessary to generate electrical pulses, as well as all dielectric isolation fittings, surge protection and electrical barriers. The wetting voltage must be a regulated DC voltage of 30 volts or less and 10 mA or less, or as otherwise determined by the Company. If Customer Installed Equipment is located within fifteen (15) feet of any gas pipeline flanges, gas regulators, or gas pressure relief devices; or if gas meters are installed in an enclosed space, then Customer Installed Equipment must be installed in accordance with National Electrical Code Class 1 Division 2 requirements.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 52.1

Standard Rate Rider — GMPS — Gas Meter Pulse Service

A failure of the pulse generator will not be detected by Company on any routine meter reading nor necessarily during other operations. Therefore, Customer is required to recognize and report any problems with the pulse generator.

RATE

In addition to any other charges set forth herein, the following charges shall apply.

For Customers Served Under Rate Schedule FT:
Monthly Charge: $ 8.10

For Customers Not Served Under Rate Schedule FT:
Monthly Charge: $21.06

If replacement of the Gas Meter(s) is necessary for the installation of a pulse generator, then Customer shall be responsible for the actual meter and meter installation cost of such Gas Meter(s). Customer shall be responsible for making at its cost any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in the event a replacement Gas Meter is necessary or as otherwise required by Company to facilitate this service.

If the Company is required to make additional visits to the meter site due to the inability to gain access to the meter location or the necessary Communication Link has not been properly installed by Customer, or the Customer's Communication Link is not working properly, the Company may charge the Customer for any additional trip to the site at a per-visit rate of $150.00.

SPECIAL TERMS AND CONDITIONS

1. All Customer Installed Equipment shall be owned, maintained and operated by Customer at its sole cost, including the installation thereof. Dielectric isolation fittings, surge protection and electrical barriers will be used by Customer at Customer's cost when connecting to Company's meter facilities. There may be instances where Company determines, in its sole discretion, that dielectric isolation fittings are not necessary. If such fittings are not determined to be necessary, Company shall notify the Customer in writing. All connections of Customer Installed Equipment to Company facilities and equipment will be made by Company or witnessed by Company's representatives. If applicable, all of Customer's Installed Equipment must be installed within fifty feet of Company's metering telemetry equipment. The Company has the right to inspect Customer's installed equipment, prior to initiating the pulse out service, but has no obligation to do so, and in conducting any inspection the Company is not undertaking or accepting any obligation, responsibility or duty whatsoever with regard to Customer Installed Equipment.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 52.1

Standard Rate Rider — GMPS — Gas Meter Pulse Service

A failure of the pulse generator will not be detected by Company on any routine meter reading nor necessarily during other operations. Therefore, Customer is required to recognize and report any problems with the pulse generator.

RATE

In addition to any other charges set forth herein, the following charges shall apply.

For Customers Served Under Rate Schedule FT or Rider TS-2: T
Monthly Charge: $ 7.25 R

For Customers Not Served Under Rate Schedule FT or Rider TS-2: T
Monthly Charge: $24.60 I

If replacement of the Gas Meter(s) is necessary for the installation of a pulse generator, then Customer shall be responsible for the actual meter and meter installation cost of such Gas Meter(s). Customer shall be responsible for making at its cost any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in the event a replacement Gas Meter is necessary or as otherwise required by Company to facilitate this service.

SPECIAL TERMS AND CONDITIONS T

1. All Customer Installed Equipment shall be owned, maintained and operated by Customer at its sole cost, including the installation thereof. Dielectric isolation fittings, surge protection and electrical barriers will be used by Customer at Customer's cost when connecting to Company's meter facilities. There may be instances where Company determines, in its sole discretion, that dielectric isolation fittings are not necessary. If such fittings are not determined to be necessary, Company shall notify the Customer in writing. All connections of Customer Installed Equipment to Company facilities and equipment will be made by Company or witnessed by Company's representatives. If applicable, all of Customer's Installed Equipment must be installed within fifty feet of Company's metering telemetry equipment. The Company has the right to inspect Customer's installed equipment, prior to initiating the pulse out service, but has no obligation to do so, and in conducting any inspection the Company is not undertaking or accepting any obligation, responsibility or duty whatsoever with regard to Customer Installed Equipment.

2. Customer agrees and understands that pulse data generated by service under this tariff shall not be used for purposes of billing by Company for natural gas volumes used by the Customer. Furthermore, Customer agrees and understands the pulse generator(s) supplied do not represent a rate of flow, but only a total volume, and should not be used for process control or other purposes. 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, Louisville, Kentucky

Standard Rate Rider GMPS
Gas Meter Pulse Service

2. Customer agrees and understands that pulse data generated by service under this tariff shall not be used for purposes of billing by Company for natural gas volumes used by the Customer. Furthermore, Customer agrees and understands the pulse generator(s) supplied do not represent a rate of flow, but only a total volume, and should not be used for process control or other purposes.

3. Customer warrants that Customer will not use pulse data in a manner that could result in or create an unsafe condition of any kind or type should the data signal from Company's natural gas metering equipment be lost or inaccurate for any reason whatsoever. Customer further warrants that any installation, operation, maintenance, repair, replacement or removal of Customer Installed Equipment shall not interfere with Company's access to or operation and maintenance of its facilities or equipment.

4. Company shall not be required to restore any lost data signal. Company reserves the right to upgrade, change, alter or remove any portion or all of Company's facilities, discontinue the data signal or require removal or disconnection of Customer's Installed Equipment, for any reason and without liability to Customer, with prior written notice to Customer. Customer may report data loss or interruptions during normal working hours to the Company. If Customer fails to comply within the time set forth in Company's written request, Company shall have the right to immediately remove Customer Installed Equipment without liability to Customer, and Customer shall reimburse Company for the actual cost of removing said Equipment. All costs associated with responding to Customer's calls and problems relating to service hereunder (including but not limited to call-out, overtime and call-back) shall be paid by Customer upon receipt of Company's invoice.

5. Company makes no representation and provides no warranty or guarantee relating to the operation of, or accuracy or availability of, the data signal provided through Company's equipment. Data received is for informational purposes only, and Company shall not be liable for Customer's use of Company's equipment or data taken therefrom for any purpose.

7. Either party may terminate service under this Rate Schedule upon sixty (60) days prior written notice. Customer shall immediately disconnect and remove Customer's Installed Equipment upon termination, or shall request Company to do so at Customer's sole cost.

8. Customer shall indemnify, defend and hold Company, its parents, affiliates and subsidiaries and their officers, directors, and employees harmless, to the extent allowed by law, from and against any and all claims, suits, causes of action, liabilities, losses, damages, penalties, fines, fees, assessments, costs and expenses (including attorney's fees and costs incurred in any action or proceeding between Company and Customer or Company and a third party) whatsoever for damages to property or injuries or death to persons (including but not limited to Company's and/or Customer's employees or contractors), arising directly or indirectly from the installation, operation, maintenance, repair, removal, or use of Customer Installed Equipment or involving any inaccurate pulse data or the reliance of Customer or any third party on any pulse data provided pursuant to service hereunder.

Standard Rate Rider GMPS
Gas Meter Pulse Service

3. Customer warrants that Customer will not use pulse data in a manner that could result in or create an unsafe condition of any kind or type should the data signal from Company's natural gas metering equipment be lost or inaccurate for any reason whatsoever. Customer further warrants that any installation, operation, maintenance, repair, replacement or removal of Customer Installed Equipment shall not interfere with Company's access to or operation and maintenance of its facilities or equipment. T

4. Company shall not be required to restore any lost data signal. Company reserves the right to upgrade, change, alter or remove any portion or all of Company's facilities, discontinue the data signal or require removal or disconnection of Customer's Installed Equipment, for any reason and without liability to Customer, with prior written notice to Customer. Customer may report data loss or interruptions during normal working hours to the Company. If Customer fails to comply within the time set forth in Company's written request, Company shall have the right to immediately remove Customer Installed Equipment without liability to Customer, and Customer shall reimburse Company for the actual cost of removing said Equipment. All costs associated with responding to Customer's calls and problems relating to service hereunder (including but not limited to call-out, overtime and call-back) shall be paid by Customer upon receipt of Company's invoice.

5. Company makes no representation and provides no warranty or guarantee relating to the operation of, or accuracy or availability of, the data signal provided through Company's equipment. Data received is for informational purposes only, and Company shall not be liable for Customer's use of Company's equipment or data taken therefrom for any purpose.

6. Either party may terminate service under this Rate Schedule upon sixty (60) days prior written notice. Customer shall immediately disconnect and remove Customer's Installed Equipment upon termination, or shall request Company to do so at Customer's sole cost. T

7. Customer shall indemnify, defend and hold Company, its parents, affiliates and subsidiaries and their officers, directors, and employees harmless, to the extent allowed by law, from and against any and all claims, suits, causes of action, liabilities, losses, damages, penalties, fines, fees, assessments, costs and expenses (including attorney's fees and costs incurred in any action or proceeding between Company and Customer or Company and a third party) whatsoever for damages to property or injuries or death to persons (including but not limited to Company's and/or Customer's employees or contractors), arising directly or indirectly from the installation, operation, maintenance, repair, removal, or use of Customer Installed Equipment or involving any inaccurate pulse data or the reliance of Customer or any third party on any pulse data provided pursuant to service hereunder. T

TERMS AND CONDITIONS T
Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof. T T T

TERMS AND CONDITIONS

Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

The proposed LG&E Gas Meter Pulse Service Rider GMPS is contained on three pages instead of the current four pages.

The proposed LG&E Rider PS-TS-2, a Pooling Service Rider for proposed Rider TS-2, is not currently available.

Standard Rate Rider **PS-TS-2** N

Pooling Service – Rider-TS-2

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to TS-2 Pool Managers.

Service under this rider shall not be available for new pool managers until the November 1 following the effective date of this rider.

For the purpose of this rider, a "TS-2 Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rider TS-2 to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties. A single Rider TS-2 customer may appoint itself as its own Pool Manager.

RATE

In addition to any charges billed directly to TS-2 Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rider TS-2, the following charge shall apply to the TS-2 Pool Manager:

PS-TS-2 Pool Administrative Charge: $75 per Customer in TS-2 Pool per month

Other: In the event that TS-2 Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then TS-2 Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

ADJUSTMENT CLAUSES

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

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

CHARACTER OF SERVICE

Service under this rider allows a TS-2 Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more transportation customers that comprise a PS-TS-2 Pool.

The TS-2 Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of the Customers in the TS-2 Pool.

The proposed LG&E Rider PS-TS-2, a Pooling Service Rider for proposed Rider TS-2, is not currently available.

The TS-2 Pool Manager must secure its own upstream capacity from Pipeline Transporter to meet the requirements of the Customers in the TS-2 Pool, up to the total Maximum Daily Quantity of the Customers who are in the TS-2 Pool.

ACTION ALERTS

Company shall have the right to issue an Action Alert ("AA") which will require actions by the TS-2 Pool Manager to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. It is the responsibility of the Pool Manager, not Company, to convey an AA to Customers in its TS-2 Pool. Pool Manager shall be responsible for complying with the directives contained in the AA.

Notice of an AA shall be provided to TS-2 Pool Manager at least eighteen (18) hours prior to the beginning of the gas day for which the AA is in effect. TS-2 Pool Manager shall respond to an AA by adjusting its deliveries to Company's system as directed in the AA within the specified timeframe.

Upon issuance of an AA, Company will direct TS-2 Pool Manager to deliver to Company from 0% to 100% of the total MDQ of those Customers in the TS-2 Pool (the PMDQ as defined hereafter). Any volume delivered by TS-2 Pool Manager that differs (either more or less) from the volume specified in the AA shall be subject to an Action Alert Charge.

Company may, in its sole discretion, issue an AA to an individual Pool Manager taking service under Rider PS-TS-2 without issuing an AA to all Pool Managers taking service under Rider PS-TS-2.

The Action Alert Charge shall be equal to $5.00 plus the mid-point price posted in *Platts Gas Daily* for Dominion South Point per Mcf on the day for which the AA was violated, plus any other charges under this rider.

Company will not be required to provide service under this rider for any TS-2 Pool Manager that does not comply with the terms or conditions of an AA. Payment of Action Alert Charges hereunder shall not be considered an exclusive remedy for failure to comply with an AA, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

IMBALANCES

Company will calculate on a daily and monthly basis the TS-2 Pool Manager's imbalance resulting from the difference between the metered usage of the Customers in the TS-2 Pool and the volumes that the TS-2 Pool Manager has delivered into Company's system for the Customers in the TS-2 Pool. This will be calculated as follows:

The proposed LG&E Rider PS-TS-2, a Pooling Service Rider for proposed Rider TS-2, is not currently available.

Imbalance = Metered Usage - Delivered Volumes

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{(\text{Metered Usage - Delivered Volumes})}{\text{Delivered Volumes}}$$

The term "day" or "daily" shall mean the period of twenty-four (24) consecutive hours beginning at 10:00 a.m. Eastern Clock Time.

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

The cash-out provision shall be applied against the aggregate volume of all Customers in a specific TS-2 Pool. The TS-2 Pool Manager will be responsible for the payment of the cash-out charges incurred by the TS-2 Pool as a result of imbalances under Rider TS-2.

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from TS-2 Pool Manager at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lowest daily mid-point price posted in *"Platts Gas Daily"* for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly negative imbalance percentage to be applied as follows:

When Total Net Negative Balance Percentage is:	The following percentage shall be multiplied by the above referenced *"Platts Gas Daily"* price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), TS-2 Pool Manager shall be billed for the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the highest daily mid-point price posted in *"Platts Gas Daily"* for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly imbalance percentage to be applied as follows:

The proposed LG&E Rider PS-TS-2, a Pooling Service Rider for proposed Rider TS-2, is not currently available.

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-referenced *"Platts Gas Daily"* price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	110%
>10% to ≤15%	120%
>15% to ≤20%	130%
>20%	140%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a TS-2 Pool Manager with a negative monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the TS-2 Pool Manager's bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rider.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

NOMINATIONS AND NOMINATED VOLUME

As further described below, TS-2 Pool Manager shall specify to Company the daily volume of gas required by the Customers in the TS-2 Pool. Such volume shall be stated in Mcf/day and converted to MMBtu/day.

At least ten (10) days prior to the beginning of each calendar month, TS-2 Pool Manager shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for the Pool Manager's TS-2 Pool.

Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by TS-2 Pool Manager to Company no later than 8:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall

The proposed LG&E Rider PS-TS-2, a Pooling Service Rider for proposed Rider TS-2, is not currently available.

not be obligated to accept from TS-2 Pool Manager daily nominations or changes thereto that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company.

Such volumes nominated by TS-2 Pool Manager shall include an allowance for Company's system average lost and unaccounted for gas ("LAUFG") expressed as a percentage and based on historical levels. Effective November 1, 2012, such LAUFG percentage is 3.52%. Such LAUFG percentage shall be revised annually each November 1 with notice provided to TS-2 Pool Manager at least thirty (30) days prior to such November 1. The volumes delivered by the TS-2 Pool Manager to Company for redelivery to Customers in the TS-2 Pool will be increased by TS-2 Pool Manager to cover the effective LAUFG percentage. For example, if the Customers in a TS-2 Pool require 325 Mcf on a given day, and the LAUFG% is 5.0%, then the Mcf nominated shall be 342 Mcf [325 / (1 - 0.05)]. The 342 Mcf shall be converted to MMBtu using a standard conversion factor as may be specified by Company from time to time. Such amount does not include any retention by the Pipeline Transporter. The volume nominated by the TS-2 Pool Manager to cover LAUFG shall not be considered in determining whether or not the TS-2 Pool Manager has exceeded the Pool Maximum Daily Quantity ("PMDQ") for the TS-2 Pool.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in a TS-2 Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rider TS-2, and no Customer shall participate in more than one pool concurrently. Except as provided for in Section 4 below, no Customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year.

2. To receive service hereunder, the PS-TS-2 Pool Manager shall enter into a PS-TS-2 Pool Management Agreement with Company. The PS-TS-2 Pool Management Agreement shall set forth the specific obligations of the TS-2 Pool Manager and Company under this rider.

   The TS-2 Pool Manager shall submit a signed PS-TS-2 Pool Management Agreement at least thirty (30) days prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the TS-2 Pool Manager of the date when service hereunder will commence. The Customers in the TS-2 Pool shall be set forth in Exhibit A of the PS-TS-2 Pool Management Agreement. In order to join a TS-2 Pool, Customer must have designated in writing its TS-2 Pool Manager as its agent pursuant to Rider TS-2. In order to modify the Customers in the pool, the Pool Manager must request a revised Exhibit A from Company and execute and return said exhibit at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective.

   The PMDQ shall be set forth in the Pool Management Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the TS-2 Pool. Company is not obligated to accept volumes for re-delivery on any day in excess of the PMDQ.

The proposed LG&E Rider PS-TS-2, a Pooling Service Rider for proposed Rider TS-2, is not currently available.

3. The TS-2 Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure TS-2 Pool Manager's performance of its obligations under the PS-TS-2 Pool Management Agreement. In determining the level of the bond or other security to be required of a TS-2 Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customers in the TS-2 Pool, the general creditworthiness of the TS-2 Pool Manager, and the TS-2 Pool Manager's prior credit record with Company, if any. In the event that the TS-2 Pool Manager defaults on its obligations under this rider or the PS-TS-2 Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy TS-2 Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-TS-2 Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The PS-TS-2 Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if a TS-2 Pool Manager fails to meet any condition of this rider and/or Rider TS-2. The PS-TS-2 Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the TS-2 Pool Manager has payments in arrears. Written notice of termination of the PS-TS-2 Pool Management Agreement shall be provided both to the TS-2 Pool Manager and to the individual Customers in the TS-2 Pool by Company.

   Customers in the TS-2 Pool will be returned to sales service under the applicable rate schedule (CGS, IGS, or AAGS), or will be allowed to enroll in another TS-2 Pool.

5. Company shall directly bill the TS-2 Pool Manager for the PS-TS-2 Pool Administrative Charge, Action Alert Charges, and cash-out charges or payments contained in Rider TS-2. The monthly bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty-seven (27) days from the date of the bill then the TS-2 Pool Manager will be considered in default.

6. Company shall directly bill the individual Customers in the TS-2 Pool for all Administrative Charges, Distribution Charges, Pipeline Supplier's Demand Component Charges, Gas Cost True-Up Charges, Basic Service Charges, Minimum Annual Threshold Charges, Monthly Telemetry Charges, and other remote metering charges, as provided for in either Rider TS-2 or Customer's otherwise applicable sales rate schedule to which Rider TS-2 is a rider.

7. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 60

Standard Rate Rider PS-TS
Pooling Service – Rate TS

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to "TS Pool Managers".

For the purpose of this rider a "TS Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rate TS to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties.

RATE
In addition to any charges billed directly to TS Pool Manager or Customer as a result of the application of Rate TS or this rider, the following charge shall apply:

PS-TS Pool Administration Charge: $75 per customer in TS Pool per month

CHARACTER OF SERVICE
Service under this rider allows a TS Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more standby sales transportation customers that comprise a PS-TS Pool.

The TS Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of customer(s) in the pool. The Cash-Out Provision of Rate TS shall be applied against the aggregate volume of all customers in a specific pool. The TS Pool Manager will be responsible for the payment of the PS-TS Pool Administration Charge and any Monthly Cash-Out payments incurred by a specific pool as a result of imbalances under Rate TS.

TERMS AND CONDITIONS
1. No customer shall participate in a TS Pool that does not individually meet the availability conditions of Rate TS, and no customer shall participate in more than one pool concurrently. Likewise, customers served under As-Available Gas Service Rate AAGS cannot be in the same pool with customers served under other sales rates.

2. To receive service hereunder, the PS-TS Pool Manager shall enter into a PS-TS Pool Management Agreement with Company and shall submit a PS-TS Application/Agency Agreement for each member of the pool, signed by both Customer and its TS Pool Manager. The PS-TS Pool Management Agreement shall set forth the specific obligations of the TS Pool Manager and Company under this rider. The PS-TS Application/Agency Agreement shall set forth the members of the pool.

   The TS Pool Manager shall submit a signed PS-TS Pool Management Agreement and a PS-TS Application/Agency Agreement for each member of the pool at least four (4) weeks prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the TS Pool Manager of the date when service hereunder will commence. A customer who terminates service under this rider or who desires to change TS Pool Managers shall likewise provide Company with a written notice at least four (4) weeks prior to the end of a billing period.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 60

Standard Rate Rider PS-TS
Pooling Service – Rider TS T

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to "TS Pool Managers".

Rider PS-TS shall continue to be effective for customers who have previously elected to transport under Rider TS as of the effective date hereof. However, service hereunder shall terminate on October 31, 2013, at which point Rider PS-TS shall no longer be in effect. T T T

For the purpose of this rider a "TS Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rider TS to perform the functions T and responsibilities of requesting and receiving information, nominating supply, and other related duties.

RATE
In addition to any charges billed directly to TS Pool Manager or Customer as a result of the application of Rider TS or this rider, the following charge shall apply: T

PS-TS Pool Administrative Charge: $75 per customer in TS Pool per month T

CHARACTER OF SERVICE
Service under this rider allows a TS Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more standby sales transportation customers that comprise a PS-TS Pool.

The TS Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of customer(s) in the pool. The Cash-Out Provision of Rider TS shall be applied against the aggregate volume of all customers in a specific pool. T The TS Pool Manager will be responsible for the payment of the PS-TS Pool Administrative Charge and any Monthly Cash-Out payments incurred by a specific pool as a result of imbalances under Rider TS. T

SPECIAL TERMS AND CONDITIONS T
1. No customer shall participate in a TS Pool that does not individually meet the availability conditions of Rider TS, and no customer shall participate in more than one pool concurrently. T Likewise, customers served under As-Available Gas Service Rate AAGS cannot be in the same pool with customers served under other sales rates.

T

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Standard Rate Rider PS-TS

Pooling Service – Rate TS

3. The TS Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure TS Pool Manager's performance of its obligations under the PS-TS Pool Management Agreement. To the extent that TS Pool Manager maintains a cash deposit with Company, Company shall refund such amount to TS Pool Manager, and TS Pool Manager shall provide Company with a surety bond, an irrevocable letter of credit, or other financial instrument satisfactory to Company in the amount determined by Company and at the time that such amount is next re-determined by Company. In determining the level of the bond or other security to be required of a TS Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of PS-TS Pool members, the general credit worthiness of the TS Pool Manager, and the TS Pool Manager's prior credit record with Company, if any. In the event that the TS Pool Manager defaults on its obligations under this rider or the PS-TS Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy TS Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-TS Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.
4. The TS Pool Manager shall provide Company with the written consent, in the form of a PS-TS Application/Agency Agreement, of all members to any change in the composition of the pool membership at least four weeks prior to the beginning of the first billing period that would apply to the modified pool. With the consent of the current pool members, the TS Pool Manager may provide written consent in the form of a PS-TS Application/Agency Agreement on behalf of the current pool members to any change in the composition of the pool. Without exception, any new pool member must provide its own written consent in the form of a PS-TS Application/Agency Agreement.
5. The PS-TS Pool Management Agreement will be terminated by Company upon four weeks written notice if a TS Pool Manager fails to meet any condition of this rider and/or Rate TS. The PS-TS Pool Management Agreement will also be terminated by Company upon four weeks written notice if the TS Pool Manager has payments in arrears. Written notice of termination of the PS-TS Pool Management Agreement shall be provided both to the TS Pool Manager and to the individual members of the pool by Company.
6. Company shall directly bill the TS Pool Manager for the PS-TS Pool Administration Charge, monthly cash-out charges or payments contained in Rate TS. The monthly bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty-seven (27) days from the date of the bill then the TS Pool Manager will be considered in default.
7. Company shall directly bill the individual customers in the pool for all Distribution Charges, Basic Service Charges, and Administrative Charges as provided for in either Rate TS or Customer's otherwise applicable sales rate schedule to which Rate TS is a Rider.

Standard Rate Rider PS-TS

Pooling Service – Rider TS T

2. To receive service hereunder, the PS-TS Pool Manager shall enter into a PS-TS Pool Management Agreement with Company and shall submit a PS-TS Application/Agency Agreement for each member of the pool, signed by both Customer and its TS Pool Manager. The PS-TS Pool Management Agreement shall set forth the specific obligations of the TS Pool Manager and Company under this rider. The PS-TS Application/Agency Agreement shall set forth the members of the pool. T

   The TS Pool Manager shall submit a signed PS-TS Pool Management Agreement and a PS-TS Application/Agency Agreement for each member of the pool at least four (4) weeks prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the TS Pool Manager of the date when service hereunder will commence. A customer who terminates service under this rider or who desires to change TS Pool Managers shall likewise provide Company with a written notice at least four (4) weeks prior to the end of a billing period.

3. The TS Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure TS Pool Manager's performance of its obligations under the PS-TS Pool Management Agreement. To the extent that TS Pool Manager maintains a cash deposit with Company, Company shall refund such amount to TS Pool Manager, and TS Pool Manager shall provide Company with a surety bond, an irrevocable letter of credit, or other financial instrument satisfactory to Company in the amount determined by Company and at the time that such amount is next re-determined by Company. In determining the level of the bond or other security to be required of a TS Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of PS-TS Pool members, the general credit worthiness of the TS Pool Manager, and the TS Pool Manager's prior credit record with Company, if any. In the event that the TS Pool Manager defaults on its obligations under this rider or the PS-TS Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy TS Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-TS Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.
4. The TS Pool Manager shall provide Company with the written consent, in the form of a PS-TS Application/Agency Agreement, of all members to any change in the composition of the pool membership at least four weeks prior to the beginning of the first billing period that would apply to the modified pool. With the consent of the current pool members, the TS Pool Manager may provide written consent in the form of a PS-TS Application/Agency Agreement on behalf of the current pool members to any change in the composition of the pool. Without exception, any new pool member must provide its own written consent in the form of a PS-TS Application/Agency Agreement.

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The proposed LG&E Rider PS-TS, a Pooling Service Rider for Rider TS, is contained on three pages instead of the current two pages.

T

5. The PS-TS Pool Management Agreement will be terminated by Company upon four weeks written notice if a TS Pool Manager fails to meet any condition of this rider and/or Rider TS. The PS-TS Pool Management Agreement will also be terminated by Company upon four weeks written notice if the TS Pool Manager has payments in arrears. Written notice of termination of the PS-TS Pool Management Agreement shall be provided both to the TS Pool Manager and to the individual members of the pool by Company.

6. Company shall directly bill the TS Pool Manager for the PS-TS Pool Administrative Charge, monthly cash-out charges or payments contained in Rider TS. The monthly bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty-seven (27) days from the date of the bill then the TS Pool Manager will be considered in default.

7. Company shall directly bill the individual customers in the pool for all Distribution Charges, Basic Service Charges, and Administrative Charges as provided for in either Rider TS or Customer's otherwise applicable sales rate schedule to which Rider TS is a Rider.

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 61

Standard Rate Rider PS-FT
Pooling Service – Rate FT

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to "FT Pool Managers".

For the purpose of this rider a "FT Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rate FT to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties.

RATE
In addition to any charges billed directly to FT Pool Manager or Customer as a result of the application of Rate FT or this rider, the following charge shall apply:

PS-FT Pool Administration Charge: $75 per customer in FT Pool per month

CHARACTER OF SERVICE
Service under this rider allows an FT Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more firm transportation customers that comprise a PS-FT Pool.

The FT Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of customer(s) in the pool. The Daily Utilization Charge, OFO Penalty and Cash-Out Provision of Rate FT shall be applied against the aggregate volume of all customers in a specific pool. The FT Pool Manager will be responsible for the payment of the PS-FT Pool Administration Charge and any Daily Utilization Charges, OFO penalties or Monthly Cash-Out payments incurred by a specific pool as a result of imbalances under Rate FT. For purposes of this rider the Daily Utilization Charge shall apply to daily imbalances that exceed ±5%, instead of the ±10% otherwise applicable in Rate FT. Company shall issue an Operational Flow Order as set forth in Rate FT to the FT Pool Manager during periods when service cannot be provided to meet daily imbalances.

TERMS AND CONDITIONS
1. No customer shall participate in an FT Pool that does not individually meet the availability conditions of Rate FT, and no customer shall participate in more than one pool concurrently. Unless a Customer meets the provisions of the Remote Metering requirement under Rate FT, that Customer shall not participate in a pool.

2. To receive service hereunder, the FT Pool Manager shall enter into a PS-FT Pool Management Agreement with Company and shall submit a PS-FT Application/Agency Agreement for each member of the pool, signed by both Customer and its Pool Manager. The PS-FT Pool Management Agreement shall set forth the specific obligations of the FT Pool Manager and Company under this rider. The PS-FT Application/Agency Agreement shall set forth the members of the pool.

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 61

Standard Rate Rider PS-FT
Pooling Service – Rate FT

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to "FT Pool Managers".

For the purpose of this rider, a "FT Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rate FT to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties.

RATE
In addition to any charges billed directly to FT Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rate FT, the following charge shall apply to FT Pool Manager: T T T

PS-FT Pool Administrative Charge: $75 per Customer in FT Pool per month T

Other: In the event that FT Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then FT Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder. T

CHARACTER OF SERVICE
Service under this rider allows an FT Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more firm transportation customers that comprise a PS-FT Pool. Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT. It is the responsibility of the FT Pool Manager to convey OFOs to Customers in its FT Pool. T

The FT Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of Customers in the FT Pool. The FT Pool Manager shall be subject to the same nomination deadlines as set forth in Rate FT. The Daily Utilization Charge, OFO Penalty and cash-out provision of Rate FT shall be applied against the aggregate volume of all Customers in a specific FT Pool. The FT Pool Manager will be responsible for the payment of the PS-FT Pool Administrative Charge and any Daily Utilization Charges, OFO penalties or monthly cash-out payments incurred by a specific FT Pool as a result of imbalances under Rate FT. For purposes of this rider the Daily Utilization Charge shall apply to daily imbalances that exceed ±2%, instead of the ±5% otherwise applicable in Rate FT. Company shall issue an Operational Flow Order as set forth in Rate FT to the FT Pool Manager during periods when service cannot be provided to meet daily imbalances. T T

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The FT Pool Manager shall submit a signed PS-FT Pool Management Agreement and a PS-FT Application/Agency Agreement for each member of the pool at least four (4) weeks prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the FT Pool Manager of the date when service hereunder will commence. A customer who terminates service under this rider or who desires to change FT Pool Managers shall likewise provide Company with a written notice at least four (4) weeks prior to the end of a billing period.

3. The FT Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure FT Pool Manager's performance of its obligations under the PS-FT Pool Management Agreement. To the extent that FT Pool Manager maintains a cash deposit with Company, Company shall refund such amount to FT Pool Manager, and FT Pool Manager shall provide Company with a surety bond, an irrevocable letter of credit, or other financial instrument satisfactory to Company in the amount determined by Company and at the time that such amount is next re-determined by Company. In determining the level of the bond or other security to be required of an FT Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of PS-FT Pool members, the general credit worthiness of the FT Pool Manager, and the FT Pool Manager's prior credit record with Company, if any. In the event that the FT Pool Manager defaults on its obligations under this rider or the PS-FT Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy FT Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-FT Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The FT Pool Manager shall provide Company with the written consent, in the form of a PS-FT Application/Agency Agreement, of all members to any change in the composition of the pool membership at least four weeks prior to the beginning of the first billing period that would apply to the modified pool. With the consent of the current pool members, the FT Pool Manager may provide written consent in the form of a PS-FT Application/Agency Agreement on behalf of the current pool members to any change in the composition of the pool. Without exception, any new pool member must provide its own written consent in the form of a PS-FT Application/Agency Agreement.

5. The PS-FT Pool Management Agreement will be terminated by Company upon four weeks written notice if an FT Pool Manager fails to meet any condition of this rider and/or Rate FT. The PS-FT Pool Management Agreement will also be terminated by Company upon four weeks written notice if the FT Pool Manager has payments in arrears. Written notice of termination of the PS-FT Pool Management Agreement shall be provided both to the FT Pool Manager and to the individual members of the pool by Company.

6. Company shall directly bill the FT Pool Manager for the PS-FT Pool Administration Charge, Utilization Charge for Daily Imbalances, monthly cash-out charges or payments, and unauthorized overrun charges under an OFO contained in Rate FT. The bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty seven (27) days from the date of the bill, then the FT Pool Manager will be considered in default.

VARIATIONS IN MMBTU CONTENT T

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in an FT Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rate FT, and no customer shall participate in more than one FT Pool concurrently. Unless a Customer meets the provisions of the Remote Metering requirement under Rate FT, that Customer shall not participate in an FT Pool.

2. To receive service hereunder, the FT Pool Manager shall enter into a PS-FT Pool Management Agreement with Company and shall submit a PS-FT Application/Agency Agreement for each Customer in the FT Pool, signed by both Customer and its FT Pool Manager. The PS-FT Pool Management Agreement shall set forth the specific obligations of the FT Pool Manager and Company under this rider. The PS-FT Application/Agency Agreement shall set forth the Customers in the FT Pool.

The FT Pool Manager shall submit a signed PS-FT Pool Management Agreement and a PS-FT Application/Agency Agreement for each Customer in the FT Pool at least thirty (30) T
days prior to the beginning of a billing period when service under this rider shall commence. T
Company shall notify the FT Pool Manager of the date when service hereunder will commence. A Customer who terminates service under this rider or who desires to change T
FT Pool Managers shall likewise provide Company with a written notice at least thirty (30) T
days prior to the end of a billing period. T

The Pool Maximum Daily Quantity ("PMDQ") shall be set forth in the Pool Management T
Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the T
FT Pool. Company is not obligated to accept volumes for re-delivery on any day in excess T
of the PMDQ. T

3. The FT Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure FT Pool Manager's performance of its obligations under the PS-FT Pool Management Agreement. In determining the level of the bond or other security to be T
required of an FT Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customers in the FT Pool, the general creditworthiness of the FT Pool Manager, and the T
FT Pool Manager's prior credit record with Company, if any. In the event that the FT Pool Manager defaults on its obligations under this rider or the PS-FT Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable T

7. Company shall directly bill the individual customers in the pool for all Distribution Charges, Administrative Charges, and remote metering charges or payments provided for in Rate FT.

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letter of credit, or other financial instrument to satisfy FT Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-FT Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner. T

4. The FT Pool Manager shall provide Company with the written consent, in the form of a PS-FT Application/Agency Agreement, of all Customers to any change in the composition of the Customers in the FT Pool at least thirty (30) days prior to the beginning of the first billing period that would apply to the modified FT Pool Such written consent for existing Customers in the FT Pool to any change in the composition of the FT Pool may be made by the FT Pool Manager as Agent for the current Customers in the FT Pool. Without exception, any new Customer in the FT Pool must provide its own written consent in the form of a PS-FT Application/Agency Agreement.

5. The PS-FT Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if an FT Pool Manager fails to meet any condition of this rider and/or Rate FT. The PS-FT Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the FT Pool Manager has payments in arrears. Written notice of termination of the PS-FT Pool Management Agreement shall be provided both to the FT Pool Manager and to the individual Customers in the FT Pool by Company.

6. Company shall directly bill the FT Pool Manager for the PS-FT Pool Administrative Charge, Utilization Charge for Daily Imbalances, cash-out charges or payments, and OFO Charges contained in Rate FT. The bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty seven (27) days from the date of the bill, then the FT Pool Manager will be considered in default.

7. Company shall directly bill the individual customers in the FT Pool for all Distribution Charges, Administrative Charges, Gas Cost True-Up Charges, Minimum Daily Threshold Charges, and remote metering charges or payments provided for in Rate FT. 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 62

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 main extensions or to other facilities which are necessary to provide basic gas 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. Customers currently being served under the Excess Facilities Rider pursuant to Original Sheet No. 52 of LG&E's Tariff PSC. of Ky. Gas No. 6, shall continue to be served thereunder.

DEFINITION OF EXCESS FACILITIES
Excess facilities are equipment and devices which are installed in addition to or in substitution for the normal facilities required to render basic gas service. Applications of excess facilities include, but are not limited to, redundant gas regulator capacity; gas filters/separators; odorant removal systems; gas compression equipment; indirect heaters; gas purification systems; additional facilities required for the customer to take service from a high-pressure gas line; and any other equipment/systems not normally installed to provide gas service to a customer.

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 1.66%

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 0.86%

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

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 62

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 main extensions or to other facilities which are necessary to provide basic gas 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. Customers currently being served under the Excess Facilities Rider pursuant to Original Sheet No. 52 of LG&E's Tariff PSC. of Ky. Gas No. 6, shall continue to be served thereunder.

DEFINITION OF EXCESS FACILITIES
Excess facilities are equipment and devices which are installed in addition to or in substitution for the normal facilities required to render basic gas service and where such facilities are T
dedicated to a specific customer. Applications of excess facilities include, but are not limited to, T
redundant gas regulator capacity; gas filters/separators; odorant removal systems; gas compression equipment; indirect heaters; gas purification systems; additional facilities required for the customer to take service from a high-pressure gas line; and any other equipment/systems not normally installed to provide gas service to a customer.

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 1.29% 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 0.48% T/R

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

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 62.1

Standard Rate Rider EF

Excess Facilities

PAYMENT

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

TERM OF CONTRACT

The initial term of contract to 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.

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 62.1

Standard Rate Rider EF

Excess Facilities

PAYMENT

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

TERM OF CONTRACT

The initial term of contract to 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.

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Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

The proposed LG&E Gas Line Tracker GLT is not currently available.

Louisville Gas and Electric Company

Adjustment Clause | GLT | N
Gas Line Tracker

APPLICABLE

Applicable to all customers receiving service under the Company's Rate Schedules RGS, VFD, CGS, IGS, AAGS, and DGGS.

CALCULATION OF THE GAS LINE TRACKER REVENUE REQUIREMENT

The GLT Revenue Requirement includes the following:

a. GLT related Plant In-Service not included in base gas rates minus the associated GLT related accumulated depreciation and accumulated deferred income taxes;
b. Retirement and removal of plant related to GLT construction;
c. The rate of return on the net rate base is the overall rate of return on capital authorized in the Company's latest base gas rate case, grossed up for federal and state income taxes;
d. Depreciation expense on the GLT-related Plant In-Service less retirement and removals; and
e. Incremental Operation and Maintenance

GLT PROGRAM FACTORS

All customers receiving service under rate schedules RGS, VFD, CGS, IGS, AAGS, and DGGS shall be assessed an adjustment to their applicable rate schedule that will enable the Company to recover the costs associated with the GLT program. After the Company replaces a gas service riser or a gas service line under this program, it will assume ownership and responsibility for the plant and equipment. The allocation of the program cost to customers will be in proportion to their relative base revenue share approved in Case No. 2012-00222.

A filing to update the projected program costs will be submitted annually at least two (2) months prior to the beginning of the effective period. The filing will reflect the anticipated impact on the Company's revenue requirements of net plant additions expected during the upcoming year. After the completion of a plan year, the Company will submit a balancing adjustment to true up the actual costs with the projected program costs for the preceding year. Such adjustment to the GLT will become effective with the first billing cycle on or after the effective date of such change.

GLT RATES

The charges for the respective gas service schedules for the first billing cycle of January 2013 are:

RGS – Residential Gas Service	$ 2.35
VFD – Volunteer Fire Department Service	$ 2.35
CGS – Commercial Gas Service	$ 11.60
IGS – Industrial Gas Service	$ 93.25
AAGS – As-Available Gas Service	$514.23
DGGS – Distributed Generation Gas Service	$ 0

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Seventh Revision of Original Sheet No. 85
Canceling P.S.C. Gas No. 8, Sixth Revision of Original Sheet No. 85

Adjustment Clause GSC
Gas Supply Clause

APPLICABLE TO
All gas sold.

GAS SUPPLY COST COMPONENT (GSCC)

Gas Supply Cost	$0.36785
Gas Cost Actual Adjustment (GCAA)	(0.01182)
Gas Cost Balance Adjustment (GCBA)	(0.01593)

Refund Factors (RF) continuing for twelve months from the effective date of each or until Company has discharged its refund obligation thereunder:

Refund Factor Effective August 1, 2011	(0.00043)
Refund Factor Effective November 1, 2011	(0.00044)
Refund Factor Effective February 1, 2012	(0.00041)
Refund Factor Effective May 1, 2012	(0.00044)
Total Refund Factor	(0.00172)
Performance-Based Rate Recovery Component (PBRRC)	0.01066
Total Gas Supply Cost Component Per 100 Cubic Feet (GSCC)	$0.34904

Date of Issue: April 26, 2012
Date Effective: May 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2012-00125 dated April 24, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 85

Adjustment Clause GSC
Gas Supply Clause

APPLICABLE TO
All gas sold.

GAS SUPPLY COST COMPONENT (GSCC)

Gas Supply Cost	$0.36785
Gas Cost Actual Adjustment (GCAA)	(0.01182)
Gas Cost Balance Adjustment (GCBA)	(0.01593)

Refund Factors (RF) continuing for twelve months from the effective date of each or until Company has discharged its refund obligation thereunder:

Refund Factor Effective August 1, 2011	(0.00043)
Refund Factor Effective November 1, 2011	(0.00044)
Refund Factor Effective February 1, 2012	(0.00041)
Refund Factor Effective May 1, 2012	(0.00044)
Total Refund Factor	(0.00172)
Performance-Based Rate Recovery Component (PBRRC)	0.01066
Total Gas Supply Cost Component Per 100 Cubic Feet (GSCC)	$0.34904

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

Issued by Authority of an Order of the KPSC in Case No. 2012-00125 dated April 24, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 85.1

Adjustment Clause **GSC**

Gas Supply Clause

The bill amount computed under each of the rate schedules to which this Gas Supply Clause is applicable shall include a Gas Supply Cost Component per 100 cubic feet of consumption calculated for each three-month period in accordance with the following formula:

GSCC = Gas Supply Cost + GCAA + GCBA + RF + PBRRC

where:

Gas Supply Cost is the expected average cost per 100 cubic feet for each three-month period determined by dividing the sum of the monthly gas supply costs by the expected deliveries to customers. Monthly gas supply cost is composed of the following:

(a) Expected total purchases at the filed rates of Company's wholesale supplier of natural gas, plus

(b) Other gas purchases for system supply, minus

(c) Portion of such purchase cost expected to be used for non-Gas Department purposes, minus

(d) Portion of such purchase cost expected to be injected into underground storage, plus

(e) Expected underground storage withdrawals at the average unit cost of working gas contained therein;

(GCAA) is the Gas Cost Actual Adjustment per 100 cubic feet which compensates for differences between the previous quarter's expected gas cost and the actual cost of gas during that quarter.

(GCBA) is the Gas Cost Balance Adjustment per 100 cubic feet which compensates for any under- or over-collections which have occurred as a result of prior adjustments.

(RF) is the sum of the Refund Factors set forth on Sheet No. 85 of this Tariff.

(PBRRC) is the amount per 100 cubic feet calculated pursuant to the Experimental Performance-Based Rate Mechanism contained in the Adjustment Clause PBR. The PBRRC is determined for each 12-month PBR period ended October 31.

Company shall file a revised Gas Supply Cost Component (GSCC) every three months giving effect to known changes in the wholesale cost of all gas purchases and the cost of gas deliveries from underground storage. The Company may make out-of-time filings when warranted. Such filing shall be made at least thirty days prior to the beginning of each three-month period and shall include the following information:

1. A copy of the tariff rate of Company's wholesale gas supplier applicable to such three-month period.
2. A statement, through the most recent three-month period for which figures are available, setting out the accumulated costs recovered hereunder compared to actual gas supply costs recorded on the books.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2010-00263 dated July 28, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 85.1

Adjustment Clause **GSC**

Gas Supply Clause

The bill amount computed under each of the rate schedules to which this Gas Supply Clause is applicable shall include a Gas Supply Cost Component per 100 cubic feet of consumption calculated for each three-month period in accordance with the following formula:

GSCC = Gas Supply Cost + GCAA + GCBA + RF + PBRRC

where:

Gas Supply Cost is the expected average cost per 100 cubic feet for each three-month period (beginning February 1, May 1, August 1, or November 1, as the case may be) determined by dividing the sum of the monthly gas supply costs by the expected deliveries to customers. Monthly gas supply cost is composed of the following: T

(a) Expected purchased gas costs (gas supply and pipeline transportation) for system supply, minus T T

(b) Portion of such expected purchased gas costs expected to be used for non-Gas Department purposes, minus T

(c) Portion of such expected purchased gas cost expected to be injected into underground storage, plus T

(d) Expected underground storage withdrawals at the average unit cost of working gas contained therein;

(GCAA) is the Gas Cost Actual Adjustment per 100 cubic feet which compensates for differences between the previous three-month period's expected gas cost and the actual cost of gas during that three-month period, plus carrying charges on any over- or under-recoveries at the Company's weighted average cost of capital, plus net uncollectible gas cost portion of bad debt. T T T T

(GCBA) is the Gas Cost Balance Adjustment per 100 cubic feet which compensates for any under- or over-collections which have occurred as a result of prior adjustments, plus carrying charges on any over- or under-recoveries at the Company's weighted average cost of capital. T T

(RF) is the sum of the Refund Factors set forth on Sheet No. 85 of this Tariff.

(PBRRC) is the amount per 100 cubic feet calculated pursuant to the Experimental Performance-Based Rate Mechanism contained in the Adjustment Clause PBR. The PBRRC is determined for each 12-month PBR period ended October 31.

Company shall file a revised Gas Supply Cost Component (GSCC) every three months giving effect to known changes in the wholesale cost of all gas purchases and the cost of gas deliveries from underground storage. The Company may make out-of-time filings when warranted. Such filing shall be made at least thirty (30) days prior to the beginning of each three-month period and shall include the following information: T

1. A copy of the tariff rate(s) of Company's pipeline transporter(s) applicable to such three-month period. 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 85.2

Adjustment Clause — GSC — Gas Supply Clause

3. A statement setting forth the supporting calculations of the Gas Supply Cost and the Gas Cost Actual Adjustment (GCAA) and the Gas Cost Balance Adjustment (GCBA) applicable to such three-month period.

To allow for the effect of Company's cycle billing, each change in the GSCC shall be placed into effect with service rendered on and after the first day of each three-month period.

In the event that Company receives from its supplier a refund of amounts paid to such supplier with respect to a prior period, Company will make adjustments in the amounts charged to its customers under this provision, as follows:

1. The "Refundable Amount" shall be the amount received by Company as a refund less any portion thereof applicable to gas purchased for electric energy production. Such Refundable Amount shall be divided by the number of hundred cubic feet of gas that Company estimates it will sell to its customers during the twelve-month period which commences with implementation of the next Gas Supply Clause filing, thus determining a "Refund Factor."
2. Effective with the implementation of the next Gas Supply Clause filing, Company will reduce, by the Refund Factor so determined, the Gas Supply Cost Component that would otherwise be applicable during the subsequent twelve-month period. Provided, however, that the period of reduced Gas Supply Cost Component will be adjusted, if necessary, in order to refund, as nearly as possible, the Refundable Amount.
3. In the event of any large or unusual refunds, Company may apply to the Public Service Commission of Kentucky for the right to depart from the refund procedure herein set forth.

Date of Issue: August 6, 2010
Date Effective: August 1, 1998
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 85.2

Adjustment Clause — GSC — Gas Supply Clause

2. A statement, through the most recent three-month period for which figures are T
available, setting out the accumulated costs recovered hereunder compared to actual T
gas supply costs recorded on the books. T

3. A statement setting forth the supporting calculations of the Gas Supply Cost and the Gas Cost Actual Adjustment (GCAA) and the Gas Cost Balance Adjustment (GCBA) applicable to such three-month period.

To allow for the effect of Company's cycle billing, each change in the GSCC shall be placed into effect with service rendered on and after the first day of each three-month period.

Company may file at least twenty (20) days prior to the beginning of any month a reduction in the T
Gas Supply Cost Component to reflect a reduction in expected purchased gas costs to remain in T
effect for the remainder of the quarter. T

In the event that Company receives from its supplier a cash refund of amounts paid to such supplier T
with respect to a prior period, Company will make adjustments in the amounts charged to its customers under this provision, as follows:

1. The "Refundable Amount" shall be the amount received by Company as a refund less
any portion thereof applicable to gas purchased for electric energy production plus T
interest at a rate equal to the average of the "3-month commercial paper rate" for the T
immediately preceding 12-month period, less ½ of 1 percent to cover the cost of T
refunding in accordance with the Order of the Commission in Case No. 7799-D. T
Such Refundable Amount shall be divided by the number of hundred cubic feet of gas that Company estimates it will sell to its customers during the twelve-month period which commences with implementation of the next Gas Supply Clause filing, thus determining a "Refund Factor."
2. Effective with the implementation of the next Gas Supply Clause filing, Company will reduce, by the Refund Factor so determined, the Gas Supply Cost Component that would otherwise be applicable during the subsequent twelve-month period. Provided, however, that the period of reduced Gas Supply Cost Component will be adjusted, if necessary, in order to refund, as nearly as possible, the Refundable Amount.
3. In the event of any large or unusual refunds, Company may apply to the Public Service Commission of Kentucky for the right to depart from the refund procedure herein set forth.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 86
Canceling P.S.C. Gas No. 8, 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 Gas Service Rate RGS, Volunteer Fire Department Rate VFD, Firm Commercial Gas Service Rate CGS, Firm Industrial Gas Service Rate IGS, As-Available Gas Service Rate AAGS, Firm Gas Transportation Rate FT, and Gas Transportation Service/Standby Rider TS. Any industrial customers who also receive electric service under Power Service Rate PS, Industrial Time-of-Day Secondary Service ITODS, Industrial Time-of-Day Primary Service ITODP, Retail Transmission Service Rate RTS, or Fluctuating Load Service Rate FLS and have elected not to participate in a demand-side management program hereunder shall not be assessed a charge pursuant to this mechanism.

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 100 cubic feet (Ccf) of monthly gas 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 Ccf sales for the upcoming twelve-month period to determine the DCR for 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 Ccf) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per Ccf for purposes of determining the lost revenue to be recovered hereunder for each customer class. The non-variable revenue requirement is defined as the weighted average price per Ccf of expected Distribution Cost Component billings for the customer classes.

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

Issued by Authority of an Order of the KPSC in Case No. 2011-00134 dated November 9, 2011

Louisville Gas and Electric Company

P.S.C. Gas No. 9, 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 Gas Service Rate RGS, Volunteer Fire Department Rate VFD, Firm Commercial Gas Service Rate CGS, Firm Industrial Gas Service Rate IGS, As-Available Gas Service Rate AAGS, Firm Gas Transportation Rate FT, and Gas Transportation
Service/Standby Rider TS, and Gas Transportation Service/Firm Balancing Rider TS-2. Any T
industrial gas customer who also receives electric service from the Company as an industrial T
customer, and has elected not to participate in a demand-side management program T
hereunder, shall not be assessed a charge pursuant to this mechanism. 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 100 cubic feet (Ccf) of monthly gas 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 Ccf sales for the upcoming twelve-month period to determine the DCR for 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 Ccf) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per Ccf for purposes of determining the lost revenue to be recovered hereunder for each customer class. The non-variable revenue requirement is defined as the weighted average price per Ccf of expected Distribution Cost Component billings for the customer classes.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 86.1
Canceling P.S.C. Gas No. 8, Original Sheet No. 86.1

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

2. The lost revenues for each customer class shall then be divided by the estimated class sales (in Ccf) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenues from lost sales calculated for a twelve-month period shall be included in the DRLS for thirty-six (36) months or until implementation of new rates pursuant to a general rate case. For recovery purposes, the lost sales revenues will be assigned 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 shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DSMI. 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:

Date of Issue: November 29, 2011
Date Effective: With Bills Rendered On and After December 30, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00134 dated November 9, 2011

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 86.1

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

2. The lost revenues for each customer class shall then be divided by the estimated class sales (in Ccf) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenues from lost sales calculated for a twelve-month period shall be included in the DRLS for thirty-six (36) months or until implementation of new rates pursuant to a general rate case. For recovery purposes, the lost sales revenues will be assigned 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 shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DSMI. 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:

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00134 dated November 9, 2011

Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 86.2
Canceling P.S.C. Gas No. 8, Original Sheet No. 86.2

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

(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 determined by calculating the difference between the amount billed during the twelve-month period from application of the DBA unit charges 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 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 balance adjustment amounts, plus interest, shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DBA for each 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).

Date of Issue: November 29, 2011
Date Effective: With Bills Rendered On and After December 30, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00134 dated November 9, 2011

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 86.2

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

(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 determined by calculating the difference between the amount billed during the twelve-month period from application of the DBA unit charges 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 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 balance adjustment amounts, plus interest, shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DBA for each 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).

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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00134 dated November 9, 2011

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Fifth Revision of Original Sheet No. 86.3
Canceling P.S.C. Gas No. 8, Fourth Revision of Original Sheet No. 86.3

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

CHANGES TO DSMRC

The filing of modifications to the DSMRC that require changes in the DCR component shall be made at least two (2) months prior to the beginning of the effective period for billing. Modifications to other components of the DSMRC shall be made at least thirty (30) 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 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 RGS and VFD Standard Gas Rate Schedules.

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.

Date of Issue: · April 30, 2012
Date Effective: May 31, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 86.3

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

CHANGES TO DSMRC

The filing of modifications to the DSMRC that require changes in the DCR component shall be made at least two (2) months prior to the beginning of the effective period for billing. Modifications to other components of the DSMRC shall be made at least thirty (30) 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 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 RGS and VFD Standard Gas Rate Schedules.

Residential Conservation / Home Energy Performance Program
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Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Third Revision of Original Sheet No. 86.4
Canceling P.S.C. Gas No. 8, Second Revision of Original Sheet No. 86.4

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Smart Energy Profile
The Smart Energy Profile Program provides a portion of LG&E'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 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. LG&E will reimburse the cost of plan reviews and inspection costs related to an Energy Star or HERS home certification.

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.

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 86.4

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Smart Energy Profile
The Smart Energy Profile Program provides a portion of LG&E'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.

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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.

Date of Issue: June 29, 2012
Date Effective: May 31, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

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 CGS, IGS, AAGS, FT and TS Standard Gas Rate Schedules.

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

Commercial Customer Program Participation Incentives:
The following Demand Side Management programs are available to commercial customers receiving service from the Company on the CGS, IGS, AAGS, FT, TS, and TS-2 Standard T
Gas Rate Schedules and Riders. T

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.

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 86.6

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors:

Residential Rate RGS and Volunteer Fire Department Rate VFD	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.01210 per Ccf
DSM Revenues from Lost Sales (DRLS)	$ 0.00241 per Ccf
DSM Incentive (DSMI)	$ 0.00054 per Ccf
DSM Capital Cost Recovery Component (DCCR)	$ 0.00554 per Ccf
DSM Balance Adjustment (DBA)	$ (0.00350) per Ccf
Total DSMRC for Rates RGS and VFD	$ 0.01709 per Ccf

Commercial Customers Served Under Firm Commercial Gas Service Rate CGS, As Available Gas Service Rate AAGS, Firm Transportation Rate FT, and Gas Transportation Service/Standby Rider TS	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00077 per Ccf
DSM Revenues from Lost Sales (DRLS)	$ 0.00000 per Ccf
DSM Incentive (DSMI)	$ 0.00000 per Ccf
DSM Capital Cost Recovery Component (DCCR)	$ 0.00052 per Ccf
DSM Balance Adjustment (DBA)	$ 0.00008 per Ccf
Total DSMRC for Rates CGS, AAGS, FT, and TS	$ 0.00137 per Ccf

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Date Effective: April 1, 2012
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 86.6

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors:

Residential Rate RGS and Volunteer Fire Department Rate VFD	Energy Charge	
DSM Cost Recovery Component (DCR)	$ 0.01210 per Ccf	
DSM Revenues from Lost Sales (DRLS)	$ 0.00241 per Ccf	
DSM Incentive (DSMI)	$ 0.00054 per Ccf	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00554 per Ccf	
DSM Balance Adjustment (DBA)	$ (0.00350) per Ccf	
Total DSMRC for Rates RGS and VFD	$ 0.01709 per Ccf	

Commercial Customers Served Under Firm Commercial Gas Service Rate CGS, As-Available Gas Service Rate AAGS, Firm Transportation Rate FT, Gas Transportation Service/Standby Rider TS, and Gas Transportation Service/Firm Balancing Service Rider TS-2	Energy Charge	T T
DSM Cost Recovery Component (DCR)	$ 0.00077 per Ccf	
DSM Revenues from Lost Sales (DRLS)	$ 0.00000 per Ccf	
DSM Incentive (DSMI)	$ 0.00000 per Ccf	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00052 per Ccf	
DSM Balance Adjustment (DBA)	$ 0.00008 per Ccf	
Total DSMRC for Rates CGS, AAGS, FT, TS, and TS-2	$ 0.00137 per Ccf	T

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

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 87

Adjustment Clause — PBR

Experimental Performance Based Rate Mechanism

APPLICABLE

To all gas sold.

RATE MECHANISM

The monthly amount computed under each of the rate schedules to which this Performance Based Ratemaking Mechanism is applicable shall be increased or decreased by the Performance Based Rate Recovery Component **(PBRRC)** at a rate per 100 cubic feet (Ccf) of monthly gas consumption. Demand costs and commodity costs shall be accumulated separately and included in the Pipeline Supplier's Demand Component and the Gas Supply Cost Component of the Gas Supply Clause (GSC), respectively. The PBRRC shall be determined for each 12-month period ended October 31 during the effective term of this experimental performance based ratemaking mechanism, which 12-month period shall be defined as the PBR period.

The PBRRC shall be computed in accordance with the following formula:

$$PBRRC = \frac{CSPBR + BA}{ES}$$

Where:

ES = Expected Ccf sales, as reflected in Company's GSC filing for the upcoming 12-month period beginning February 1.

CSPBR = Company Share of Performance Based Ratemaking Mechanism savings or expenses. The CSPBR shall be calculated as follows:

$$CSPBR = TPBRR \times ACSP$$

Where:

TPBRR = Total Performance Based Ratemaking Results. The TPBRR shall be savings or expenses created during the PBR Period. TPBRR shall be calculated as follows:

$$TPBRR = (GAIF + TIF + OSSIF)$$

GAIF

GAIF = Gas Acquisition Index Factor. The GAIF shall be calculated by comparing the total annual Benchmark Gas Costs **(BGC)** for system supply natural gas purchases for the PBR period to the total annual Actual Gas Costs **(AGC)** for system supply natural gas purchases during the same period to determine if any Shared Expenses or Shared Savings exist.

The BGC shall include two benchmark components as follows:

$$BGC = TABMGCC + HRF$$

Date of Issue: August 6, 2010
Date Effective: October 26, 2001
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 87

Adjustment Clause — PBR

Experimental Performance Based Rate Mechanism

APPLICABLE

To all gas sold.

RATE MECHANISM

The monthly amount computed under each of the rate schedules to which this Performance Based Ratemaking Mechanism is applicable shall be increased or decreased by the Performance Based Rate Recovery Component **(PBRRC)** at a rate per 100 cubic feet (Ccf) of monthly gas consumption. Demand costs and commodity costs shall be accumulated separately and included in the Pipeline Supplier's Demand Component and the Gas Supply Cost Component of the Gas Supply Clause (GSC), respectively. The PBRRC shall be determined for each 12-month period ended October 31 during the effective term of this experimental performance based ratemaking mechanism, which 12-month period shall be defined as the PBR period.

The PBRRC shall be computed in accordance with the following formula:

$$PBRRC = \frac{CSPBR + BA}{ES}$$

Where:

ES = Expected Ccf sales, as reflected in Company's GSC filing for the upcoming 12-month period beginning February 1.

CSPBR = Company Share of Performance Based Ratemaking Mechanism savings or expenses. The CSPBR shall be calculated as follows:

$$CSPBR = TPBRR \times ACSP$$

Where:

TPBRR = Total Performance Based Ratemaking Results. The TPBRR shall be savings or expenses created during the PBR Period. TPBRR shall be calculated as follows:

$$TPBRR = (GAIF + TIF + OSSIF)$$

GAIF

GAIF = Gas Acquisition Index Factor. The GAIF shall be calculated by comparing the total annual Benchmark Gas Costs **(BGC)** for system supply natural gas purchases for the PBR period to the total annual Actual Gas Costs **(AGC)** for system supply natural gas purchases during the same period to determine if any Shared Expenses or Shared Savings exist.

The BGC shall include two benchmark components as follows:

$$BGC = TABMGCC + HRF$$

Date of Issue: June 29, 2012
Date Effective: October 26, 2001
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 87.1
Canceling P.S.C. Gas No. 8, Original Sheet No. 87.1

Adjustment Clause **PBR**

Experimental Performance Based Rate Mechanism

Where:

TABMGCC represents the Total Annual Benchmark Gas Commodity Costs and is the annual sum of the monthly Benchmark Gas Commodity Costs **(BMGCC)** of gas purchased for system supply; and

HRF represents Historical Reservation Fees and is an annual dollar amount equal to Company's average annual supply reservation fees based on the 24-month period ended October 31 immediately preceding the PBR period.

BMGCC represents Benchmark Gas Commodity Costs and shall be calculated on a monthly basis and accumulated for the PBR period. BMGCC shall be calculated as follows:

BMGCC = Sum {[SZFQE%i x (APV - PEFDCQ)x SAIi]} + [PEFDCQ x DAI]

Where:

SZFQE% is the Supply Zone Firm Quantity Entitlement Percentage derived from Company's firm entitlements by pipeline and by zone for which indices are posted. The percentage represents the pro-rata portion of Company's firm lateral and mainline receipt point quantity entitlements by zone for each transportation contract by pipeline.

i represents each supply area.

APV is the actual purchased volumes of natural gas for system supply for the month. The APV shall include purchases necessary to cover retention volumes required by the pipeline as fuel.

PEFDCQ are the Purchases In Excess of Firm Daily Contract Quantities delivered to Company's city gate. Firm Daily Contract Quantities are the maximum daily contract quantities which Company can deliver to its city gate under its various firm transportation agreements and arrangements.

SAI is the Supply Area Index factor to be established for each supply area in which Company has firm transportation entitlements used to transport its natural gas purchases and for which price postings are available. The five supply areas are TGT-SL (Texas Gas Transmission - Zone SL), TGT-1 (Texas Gas Transmission - Zone 1), TGT-4 (Texas Gas Transmission – Zone 4), TGPL-0 (Tennessee Gas Pipeline - Zone 0), and TGPL-1 (Tennessee Gas Pipeline - Zone 1).

The monthly SAI for TGT-SL, TGT-1, TGT-4, TGPL-0 and TGPL-1 shall be calculated using the following formula:

SAI = [I(1) + I(2) + I(3)] / 3

DAI is the Delivery Area Index to be established for purchases made by Company when Company has fully utilized its pipeline quantity entitlements on a daily basis and which are for delivery to Company's city gate from either Texas Gas Transmission's Zone 4 or Tennessee Gas Pipeline's Zone 2.

Date of Issue: May 4, 2010
Date Effective: November 1, 2001
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00550 dated April 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 87.1

Adjustment Clause **PBR**

Experimental Performance Based Rate Mechanism

Where:

TABMGCC represents the Total Annual Benchmark Gas Commodity Costs and is the annual sum of the monthly Benchmark Gas Commodity Costs **(BMGCC)** of gas purchased for system supply; and

HRF represents Historical Reservation Fees and is an annual dollar amount equal to Company's average annual supply reservation fees based on the 24-month period ended October 31 immediately preceding the PBR period.

BMGCC represents Benchmark Gas Commodity Costs and shall be calculated on a monthly basis and accumulated for the PBR period. BMGCC shall be calculated as follows:

BMGCC = Sum {[SZFQE%i x (APV - PEFDCQ)x SAIi]} + [PEFDCQ x DAI]

Where:

SZFQE% is the Supply Zone Firm Quantity Entitlement Percentage derived from Company's firm entitlements by pipeline and by zone for which indices are posted. The percentage represents the pro-rata portion of Company's firm lateral and mainline receipt point quantity entitlements by zone for each transportation contract by pipeline.

i represents each supply area.

APV is the actual purchased volumes of natural gas for system supply for the month. The APV shall include purchases necessary to cover retention volumes required by the pipeline as fuel.

PEFDCQ are the Purchases In Excess of Firm Daily Contract Quantities delivered to Company's city gate. Firm Daily Contract Quantities are the maximum daily contract quantities which Company can deliver to its city gate under its various firm transportation agreements and arrangements.

SAI is the Supply Area Index factor to be established for each supply area in which Company has firm transportation entitlements used to transport its natural gas purchases and for which price postings are available. The five supply areas are TGT-SL (Texas Gas Transmission - Zone SL), TGT-1 (Texas Gas Transmission - Zone 1), TGT-4 (Texas Gas Transmission – Zone 4), TGPL-0 (Tennessee Gas Pipeline - Zone 0), and TGPL-1 (Tennessee Gas Pipeline - Zone 1).

The monthly SAI for TGT-SL, TGT-1, TGT-4, TGPL-0 and TGPL-1 shall be calculated using the following formula:

SAI = [I(1) + I(2) + I(3)] / 3

DAI is the Delivery Area Index to be established for purchases made by Company when Company has fully utilized its pipeline quantity entitlements on a daily basis and which are for delivery to Company's city gate from either Texas Gas Transmission's Zone 4 or Tennessee Gas Pipeline's Zone 2.

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

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Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 87.2
Canceling P.S.C. Gas No. 8, Original Sheet No. 87.2

Adjustment Clause PBR

Experimental Performance Based Rate Mechanism

The monthly DAI for TGT-4 and TGPL-2 shall be calculated using the following formula:

DAI = [I(1) + I(2) + I(3)] / 3

Where:

I represents each index reflective of both supply area prices and price changes throughout the month in these various supply areas.

The indices for each supply zone are as follows:

SAI (TGT-SL)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Gas Daily* postings for Louisiana - Onshore South Texas Gas Zone SL averaged for the month.

I(3) is the *Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas Zone SL.

SAI (TGT-1)

I(1) is the average of weekly *Natural Gas Week* postings for North Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Gas Daily* postings for East Texas - North Louisiana Area -Texas Gas Zone 1 averaged for the month.

I(3) is the *Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas Zone1.

SAI (TGT-4)

I(1) is the average of weekly *Natural Gas Week* postings for Spot Prices on Interstate Pipeline Systems for Lebanon Hub.

I(2) is the average of the daily high and low *Gas Daily* postings for Appalachia – Lebanon Hub averaged for the month.

I(3) is the *Inside FERC's - Gas Market Report* first-of-the-month posting for Northeast – Lebanon Hub.

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Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00550 dated April 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 87.2

Adjustment Clause PBR

Experimental Performance Based Rate Mechanism

The monthly DAI for TGT-4 and TGPL-2 shall be calculated using the following formula:

DAI = [I(1) + I(2) + I(3)] / 3

Where:

I represents each index reflective of both supply area prices and price changes throughout the month in these various supply areas.

The indices for each supply zone are as follows:

SAI (TGT-SL)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for Louisiana - Onshore South Texas Gas Zone SL averaged for the month. T

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas Zone SL. T

SAI (TGT-1)

I(1) is the average of weekly *Natural Gas Week* postings for North Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for East Texas - North Louisiana Area -Texas Gas Zone 1 averaged for the month. T

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas Zone1. T

SAI (TGT-4)

I(1) is the average of weekly *Natural Gas Week* postings for Spot Prices on Interstate Pipeline Systems for Lebanon Hub.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for Appalachia – Lebanon Hub averaged for the month. T

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Northeast – Lebanon Hub. 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 87.3
Canceling P.S.C. Gas No. 8, Original Sheet No. 87.3

Adjustment Clause PBR
Experimental Performance Based Rate Mechanism

SAI (TGPL-0)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Texas as Delivered to Pipeline.

I(2) is the average of the daily high and low *Gas Daily* postings for South – Corpus Christi-Tennessee averaged for the month.

I(3) is the *Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee Zone 0.

SAI (TGPL-1)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Gas Daily* postings for Louisiana – Onshore South – Tennessee 500 Leg averaged for the month.

I(3) is the *Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee 500 leg.

DAI (TGT-4) and (TGPL-2)

I(1) is the average of weekly *Natural Gas Week* postings for Spot Prices on Interstate Pipeline Systems for Dominion - South.

I(2) is the average of the daily high and low *Gas Daily* postings for the Daily Price Survey for Appalachia - Dominion South Point.

I(3) is the *Inside FERC's - Gas Market Report* first-of-the-month posting for Prices of Spot Gas Delivered to Pipeline for Dominion Transmission Inc. - Appalachia.

AGC represents Company's total annual Actual Gas Costs of natural gas purchased for system supply and is equal to the total monthly actual gas commodity costs and supply reservation fees plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments paid by Company to its suppliers accumulated for the PBR period. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

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Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 87.3

Adjustment Clause PBR
Experimental Performance Based Rate Mechanism

SAI (TGPL-0)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Texas as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for South – Corpus Christi-Tennessee averaged for the month. T

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee Zone 0. T

SAI (TGPL-1)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for Louisiana – Onshore South – Tennessee 500 Leg averaged for the month. T

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee 500 leg. T

DAI (TGT-4) and (TGPL-2)

I(1) is the average of weekly *Natural Gas Week* postings for Spot Prices on Interstate Pipeline Systems for Dominion - South.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for the Daily Price Survey for Appalachia - Dominion South Point. T

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Prices of Spot Gas Delivered to Pipeline for Dominion Transmission Inc. - Appalachia. T

AGC represents Company's total annual Actual Gas Costs of natural gas purchased for system supply and is equal to the total monthly actual gas commodity costs and supply reservation fees plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments paid by Company to its suppliers accumulated for the PBR period. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 87.4
Canceling P.S.C. Gas No. 8, Original Sheet No. 87.4

Adjustment Clause PBR

Experimental Performance Based Rate Mechanism

To the extent that AGC exceeds BGC for the PBR period, then the GAIF Shared Expenses shall be computed as follows:

Shared Expenses = AGC - BGC

To the extent that AGC is less than BGC for the PBR period, then the GAIF Shared Savings shall be computed as follows:

Shared Savings = BGC – AGC

<u>TIF</u>

TIF = Transportation Index Factor. The Transportation Index Factor shall be calculated by comparing the Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** of natural gas transportation services during the PBR period, to the Total Annual Actual Gas Transportation Costs **(TAAGTC)** applicable to the same period to determine if any Shared Expenses or Shared Savings exist.

The Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** are calculated as follows:

TABMGTC = Annual Sum of Monthly BMGTC

Where:

BMGTC is the Benchmark Monthly Gas Transportation Costs which include both demand and volumetric costs associated with natural gas pipeline transportation services. The BMGTC shall be accumulated for the PBR period and shall be calculated as follows:

BMGTC = Sum [BM(TGT) + BM(TGPL) + BM(PPL)]

Where:

BM(TGT) is the benchmark associated with Texas Gas Transmission Corporation.

BM(TGPL) is the benchmark associated with Tennessee Gas Pipeline Company.

Date of Issue: May 4, 2010
Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00550 dated April 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 87.4

Adjustment Clause PBR

Experimental Performance Based Rate Mechanism

To the extent that AGC exceeds BGC for the PBR period, then the GAIF Shared Expenses shall be computed as follows:

Shared Expenses = AGC - BGC

To the extent that AGC is less than BGC for the PBR period, then the GAIF Shared Savings shall be computed as follows:

Shared Savings = BGC – AGC

<u>TIF</u>

TIF = Transportation Index Factor. The Transportation Index Factor shall be calculated by comparing the Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** of natural gas transportation services during the PBR period, to the Total Annual Actual Gas Transportation Costs **(TAAGTC)** applicable to the same period to determine if any Shared Expenses or Shared Savings exist.

The Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** are calculated as follows:

TABMGTC = Annual Sum of Monthly BMGTC

Where:

BMGTC is the Benchmark Monthly Gas Transportation Costs which include both demand and volumetric costs associated with natural gas pipeline transportation services. The BMGTC shall be accumulated for the PBR period and shall be calculated as follows:

BMGTC = Sum [BM(TGT) + BM(TGPL) + BM(PPL)]

Where:

BM(TGT) is the benchmark associated with Texas Gas Transmission Corporation.

BM(TGPL) is the benchmark associated with Tennessee Gas Pipeline Company.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00550 dated April 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 87.5
Canceling P.S.C. Gas No. 8, Original Sheet No. 87.5

Adjustment Clause PBR
Experimental Performance Based Rate Mechanism

BM(PPL) is the benchmark associated with a proxy pipeline. The appropriate benchmark, which will be determined at the time of purchase, will be used to benchmark purchases of transportation capacity from non-traditional sources.

The benchmark associated with each pipeline shall be calculated as follows:

BM(TGT) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(TGPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(PPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

Where:

TPDR is the applicable Tariffed Pipeline Demand Rate.
DQ is the Demand Quantities contracted for by Company from the applicable transportation provider.

TPCR is the applicable Tariffed Pipeline Commodity Rate.

AV is the Actual Volumes delivered at Company's city-gate by the applicable transportation provider for the month.

S&DB represents Surcharges, Direct Bills and other applicable amounts approved by the Federal Energy Regulatory Commission (FERC). Such amounts are limited to FERC-approved charges such as surcharges, direct bills, cashouts, take-or-pay amounts, Gas Supply Realignment and other Order 636 transition costs.

The Total Annual Actual Gas Transportation Costs (**TAAGTC)** paid by Company for the PBR period shall include both demand and volumetric costs associated with natural gas pipeline transportation services as well as all applicable FERC-approved surcharges, direct bills and cashouts included in S&DB, plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

To the extent that TAAGTC exceeds TABMGTC for the PBR period, then the TIF Shared Expenses shall be computed as follows:

Shared Expenses = TAAGTC – TABMGTC

To the extent that TAAGTC is less than TABMGTC for the PBR period, then the TIF Shared Savings shall be computed as follows:

Date of Issue: May 4, 2010
Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00550 dated April 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 87.5

Adjustment Clause PBR
Experimental Performance Based Rate Mechanism

BM(PPL) is the benchmark associated with a proxy pipeline. The appropriate benchmark, which will be determined at the time of purchase, will be used to benchmark purchases of transportation capacity from non-traditional sources.

The benchmark associated with each pipeline shall be calculated as follows:

BM(TGT) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(TGPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(PPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

Where:

TPDR is the applicable Tariffed Pipeline Demand Rate.
DQ is the Demand Quantities contracted for by Company from the applicable transportation provider.

TPCR is the applicable Tariffed Pipeline Commodity Rate.

AV is the Actual Volumes delivered at Company's city-gate by the applicable transportation provider for the month.

S&DB represents Surcharges, Direct Bills and other applicable amounts approved by the Federal Energy Regulatory Commission (FERC). Such amounts are limited to FERC-approved charges such as surcharges, direct bills, cashouts, take-or-pay amounts, Gas Supply Realignment and other Order 636 transition costs.

The Total Annual Actual Gas Transportation Costs (**TAAGTC)** paid by Company for the PBR period shall include both demand and volumetric costs associated with natural gas pipeline transportation services as well as all applicable FERC-approved surcharges, direct bills and cash-outs included in S&DB, plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses. T

To the extent that TAAGTC exceeds TABMGTC for the PBR period, then the TIF Shared Expenses shall be computed as follows:

Shared Expenses = TAAGTC – TABMGTC

To the extent that TAAGTC is less than TABMGTC for the PBR period, then the TIF Shared Savings shall be computed 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 87.6
Canceling P.S.C. Gas No. 8, Original Sheet No. 87.6

Adjustment Clause PBR

Experimental Performance Based Rate Mechanism

Shared Savings = TABMGTC - TAAGTC

Should one of Company's pipeline transporters file a rate change effective during any PBR period and bill such proposed rates subject to refund, the period over which the benchmark comparison is made for the relevant transportation costs will be extended for one or more 12-month periods, until the FERC has approved final settled rates, which will be used as the appropriate benchmark. Company will not share in any of the savings or expenses related to the affected pipeline until final settled rates are approved.

OSSIF

OSSIF = Off-System Sales Index Factor. The Off-System Sales Index Factor shall be equal to the Net Revenue from Off-System Sales **(NR)**.

Net Revenue is calculated as follows:

NR = OSREV - OOPC

Where:

OSREV is the total revenue associated with off-system sales and storage service transactions.

OOPC is the out-of-pocket costs associated with off-system sales and storage service transactions, and shall be determined as follows:

OOPC = OOPC(GC) + OOPC(TC) + OOPC(SC) + OOPC(UGSC) + Other Costs

Where:

OOPC(GC) is the Out-of-Pocket Gas Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm supply contracts, the OOPC(GC) shall be the incremental cost to purchase the gas available under Company's firm supply contracts. For off-system sales not using Company's firm supply contracts, the OOPC(GC) shall be the incremental costs to purchase the gas from other entities.

OOPC(TC) is the Out-of-Pocket Transportation Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm transportation agreements, the OOPC(TC) shall be the incremental cost to use the transportation available under Company's firm supply contracts. For off-system sales not using Company's firm transportation agreements, the OOPC(TC) shall be the incremental costs to purchase the transportation from other entities.

Date of Issue: May 4, 2010
Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00550 dated April 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 87.6

Adjustment Clause PBR

Experimental Performance Based Rate Mechanism

Shared Savings = TABMGTC - TAAGTC

Should one of Company's pipeline transporters file a rate change effective during any PBR period and bill such proposed rates subject to refund, the period over which the benchmark comparison is made for the relevant transportation costs will be extended for one or more 12-month periods, until the FERC has approved final settled rates, which will be used as the appropriate benchmark. Company will not share in any of the savings or expenses related to the affected pipeline until final settled rates are approved.

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Where:

OSREV is the total revenue associated with off-system sales and storage service transactions.

OOPC is the out-of-pocket costs associated with off-system sales and storage service transactions, and shall be determined as follows:

OOPC = OOPC(GC) + OOPC(TC) + OOPC(SC) + OOPC(UGSC) + Other Costs

Where:

OOPC(GC) is the Out-of-Pocket Gas Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm supply contracts, the OOPC(GC) shall be the incremental cost to purchase the gas available under Company's firm supply contracts. For off-system sales not using Company's firm supply contracts, the OOPC(GC) shall be the incremental costs to purchase the gas from other entities.

OOPC(TC) is the Out-of-Pocket Transportation Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm transportation agreements, the OOPC(TC) shall be the incremental cost to use the transportation available under Company's firm supply contracts. For off-system sales not using Company's firm transportation agreements, the OOPC(TC) shall be the incremental costs to purchase the transportation from other entities.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00550 dated April 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 87.7
Canceling P.S.C. Gas No. 8, Original Sheet No. 87.7

Adjustment Clause PBR

Experimental Performance Based Rate Mechanism

OOPC(SC) is the Out-of-Pocket Storage Costs associated with off-system sales of storage. If this is gas in Company's own storage it shall be priced at the average price of the gas in Company's storage during the month of the sale. If this is gas from the storage component of Texas Gas's No-Notice Service, this gas shall be priced at the replacement cost.

OOPC(UGSC) is the Out-of-Pocket Underground Storage Costs associated with off-system sales of storage services. For the off-systems sales of storage services utilizing Company's on-system storage, the OOPC(UGSC) shall include incremental storage losses, odorization, and other fuel-related costs such as purification, dehydration, and compression. Such costs shall exclude labor-related expenses.

Other Costs represent all other incremental costs and include, but are not limited to, costs such as applicable sales taxes and excise fees plus the gains and/or losses from the use of financial hedging instruments and the transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

ACSP

ACSP = Applicable Company Sharing Percentage. The ACSP shall be determined based on the PTAGSC.

Where:

PTAGSC = Percentage of Total Actual Gas Supply Costs. The PTAGSC shall be the TPBRR stated as a Percentage of Total Actual Gas Supply Costs and shall be calculated as follows:

$$\text{PTAGSC} = \frac{\text{TPBRR}}{\text{TAGSC}}$$

Where:

TAGSC = Total Actual Gas Supply Costs. The TAGSC shall be calculated as follows:

$$\text{TAGSC} = \text{AGC} + \text{TAAGTC}$$

If the absolute value of the PTAGSC is less than or equal to 4.5%, then the ACSP of 25% shall be applied to TPBRR to determine CSPBR. If the absolute value of the PTAGSC is greater than 4.5%, then the ACSP of 25% shall be applied to the amount of TPBRR that is equal to 4.5% of TAGSC to determine a portion of CSPBR, and the ACSP of 50% shall be applied to the amount of TPBRR that is in excess of 4.5% of TAGSC to determine a portion of CSPBR. These two portions are added together to produce the total CSPBR.

Date of Issue: May 4, 2010
Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00550 dated April 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 87.7

Adjustment Clause PBR

Experimental Performance Based Rate Mechanism

OOPC(SC) is the Out-of-Pocket Storage Costs associated with off-system sales of storage. If this is gas in Company's own storage it shall be priced at the average price of the gas in Company's storage during the month of the sale. If this is gas from the storage component of Texas Gas's No-Notice Service, this gas shall be priced at the replacement cost.

OOPC(UGSC) is the Out-of-Pocket Underground Storage Costs associated with off-system sales of storage services. For the off-systems sales of storage services utilizing Company's on-system storage, the OOPC(UGSC) shall include incremental storage losses, odorization, and other fuel-related costs such as purification, dehydration, and compression. Such costs shall exclude labor-related expenses.

Other Costs represent all other incremental costs and include, but are not limited to, costs such as applicable sales taxes and excise fees plus the gains and/or losses from the use of financial hedging instruments and the transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

ACSP

ACSP = Applicable Company Sharing Percentage. The ACSP shall be determined based on the PTAGSC.

Where:

PTAGSC = Percentage of Total Actual Gas Supply Costs. The PTAGSC shall be the TPBRR stated as a Percentage of Total Actual Gas Supply Costs and shall be calculated as follows:

$$\text{PTAGSC} = \frac{\text{TPBRR}}{\text{TAGSC}}$$

Where:

TAGSC = Total Actual Gas Supply Costs. The TAGSC shall be calculated as follows:

$$\text{TAGSC} = \text{AGC} + \text{TAAGTC}$$

If the absolute value of the PTAGSC is less than or equal to 4.5%, then the ACSP of 25% shall be applied to TPBRR to determine CSPBR. If the absolute value of the PTAGSC is greater than 4.5%, then the ACSP of 25% shall be applied to the amount of TPBRR that is equal to 4.5% of TAGSC to determine a portion of CSPBR, and the ACSP of 50% shall be applied to the amount of TPBRR that is in excess of 4.5% of TAGSC to determine a portion of CSPBR. These two portions are added together to produce the total CSPBR.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00550 dated April 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 87.8
Canceling P.S.C. Gas No. 8, Original Sheet No. 87.8

Adjustment Clause PBR

Experimental Performance Based Rate Mechanism

BA

BA = Balance Adjustment. The BA is used to reconcile the difference between the amount of revenues billed or credited through the CSPBR and previous application of the BA and revenues which should have been billed or credited, as follows:

1) For the CSPBR, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the CSPBR and the actual amount used to establish the CSPBR for the period.

2) For the BA, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the BA and the actual amount used to establish the BA for the period.

Review

Within 60 days of the end of the fourth year of the five-year extension, Company will file an assessment and review of the PBR mechanism for the first four years of the five-year extension period. In that report and assessment, Company will make any recommended modifications to the PBR mechanism.

Date of Issue: May 4, 2010
Date Effective: November 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00550 dated April 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 87.8

Adjustment Clause PBR

Experimental Performance Based Rate Mechanism

BA

BA = Balance Adjustment. The BA is used to reconcile the difference between the amount of revenues billed or credited through the CSPBR and previous application of the BA and revenues which should have been billed or credited, as follows:

1) For the CSPBR, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the CSPBR and the actual amount used to establish the CSPBR for the period.

2) For the BA, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the BA and the actual amount used to establish the BA for the period.

Review

Within 60 days of the end of the fourth year of the five-year extension, Company will file an assessment and review of the PBR mechanism for the first four years of the five-year extension period. In that report and assessment, Company will make any recommended modifications to the PBR mechanism.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00550 dated April 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 88

Adjustment Clause WNA
Weather Normalization Adjustment Clause Applicable to Rates RGS and CGS

WEATHER NORMALIZATION ADJUSTMENT (WNA)

The sales to Residential and Commercial Customers under Rate Schedules RGS and CGS shall be increased or decreased monthly by an amount hereinafter described as the Weather Normalization Adjustment (WNA).

Determination of WNA

Weather normalized volumes shall be utilized during the November through April billing periods to calculate the non-gas portion of the bills of all heating Customers served under Rate Schedules RGS and CGS. During the remainder of the year, May through October, the bills shall be computed based on actual consumption.

Weather Normalization Adjustment will be calculated using the following formula:

WNA = [(Actual Mcf - Base Load Mcf) * (Normal Degree Days/Actual Degree Days)]

Each Customer's base load will be determined individually, and will be recomputed annually. Rates used in the computation of the WNA shall be determined based on the applicable base rate charge as set forth on the RGS and CGS Rate Schedules.

Date of Issue: August 6, 2010
Date Effective: September 27, 2000
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 88

Adjustment Clause WNA
Weather Normalization Adjustment Clause Applicable to Rates RGS and CGS

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Each Customer's base load will be determined individually, and will be recomputed annually. Rates used in the computation of the WNA shall be determined based on the applicable base rate charge as set forth on the RGS and CGS Rate Schedules.

Date of Issue: June 29, 2012
Date Effective: September 27, 2000
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

Adjustment Clause

Franchise Fee

APPLICABILITY

All gas rate schedules.

MONTHLY CHARGE

A surcharge shall be calculated and added to the total bill for gas service for all customers located within local governmental jurisdictions which currently or in the future impose municipal franchise fees or other local taxes on the Company by ordinance, franchise, or otherwise. Such fees or taxes shall be net of any corresponding fees or taxes which are currently included in the base charges of each rate schedule.

The amount calculated shall be applied exclusively to the bills of customers receiving service within the territorial limits of the authority imposing the fee or tax. The fee or tax shall be added to the customer's bill as a separate item. Where more than one such fee or tax is imposed, each of the fees or taxes applicable to each customer shall be added to the bills as separately identified items.

Date of Issue: August 6, 2010
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

Adjustment Clause

Franchise Fee

APPLICABILITY

All gas rate schedules.

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The amount calculated shall be applied exclusively to the bills of customers receiving service within the territorial limits of the authority imposing the fee or tax. The fee or tax shall be added to the customer's bill as a separate item. Where more than one such fee or tax is imposed, each of the fees or taxes applicable to each customer shall be added to the bills as separately identified items.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 91

Adjustment Clause — ST
School Tax

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
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RATE
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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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Second Revision of Original Sheet No. 92
Canceling P.S.C. Gas No. 8, First Revision of Original Sheet No. 92

Adjustment Clause — HEA
Home Energy Assistance

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 gas 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00162 dated December 15, 2011

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 92

Adjustment Clause — HEA
Home Energy Assistance

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 gas 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2011-00162 dated December 15, 2011

Louisville Gas and Electric Company

P.S.C. Gas No. 8, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

All gas 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 gas 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 gas 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 gas service

Date of Issue: August 6, 2010
Date Effective: February 6, 2009
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

All gas 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 gas 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 gas 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 gas service

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Date Effective: August 1, 2010
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Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 97

TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

A written application or contract, properly executed, may be required before Company is obligated to render gas 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 gas service is clearly outside the scope of Company's standard rate schedules, Company may establish special terms and require special contracts giving effect to such unusual circumstances.

TRANSFER OF APPLICATION

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

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, the 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 months.

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 Customers 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.

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 97

TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

A written application or contract, properly executed, may be required before Company is obligated to render gas 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 gas service is clearly outside the scope of Company's standard rate schedules, Company may establish special terms and require special contracts giving effect to such unusual circumstances.

TRANSFER OF APPLICATION

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

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, the 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 months.

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 Customers will at all times be served under the most beneficial rate.

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Louisville Gas and Electric Company

TERMS AND CONDITIONS

Customer Responsibilities

CUSTOMER'S EQUIPMENT AND INSTALLATION.

Customer shall furnish, install, and maintain at Customer's expense the necessary Customer's Service Line extending from Company's Service Connection at the property line to the building or place of utilization of the gas.

All piping, appliances, and other gas equipment and apparatus, except the meter and regulator, located on and within the Customer's premises beyond point of connection with Company's Service Connection at the property line shall be furnished and installed by and at the expense of Customer, and shall be maintained by Customer in good and safe condition. Company assumes no responsibility whatsoever for the condition of Customer's piping, apparatus or appliances, nor for the maintenance or renewal of any portion thereof.

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 gas service or for the purpose of turning on and shutting off the gas supply 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.

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

Gas service shall not be used for purposes other than as set forth in customer's application or contract.

LIABILITY

Customer assumes all responsibility for the gas service upon Customer's premises at and from the point of delivery of gas and for the pipes 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 gas, occasioned by such gas or said pipes and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence of Company.

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Louisville Gas and Electric Company

TERMS AND CONDITIONS

Customer Responsibilities

CUSTOMER'S EQUIPMENT AND INSTALLATION.

Customer shall furnish, install, and maintain at Customer's expense the necessary Customer's Service Line extending from Company's Service Connection at the property line to the building or place of utilization of the gas.

All piping, appliances, and other gas equipment and apparatus, except the meter, regulator, T
and any gas riser or service line the Company has installed, repaired, or replaced, located on T
and within the Customer's premises beyond point of connection with Company's Service Connection at the property line shall be furnished and installed by and at the expense of Customer, and shall be maintained by Customer in good and safe condition. Company assumes no responsibility whatsoever for the condition of Customer's piping, apparatus or appliances, nor for the maintenance or renewal of any portion thereof.

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 gas service or for the purpose of turning on and shutting off the gas supply 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

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EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

Gas service shall not be used for purposes other than as set forth in customer's application or contract.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 97.2

TERMS AND CONDITIONS

Customer Responsibilities

NOTICE TO COMPANY OF CHANGES IN CUSTOMER'S LOAD

The service pipes, meters, and appurtenances supplied by Company for the rendition of gas service to its customers have a definite capacity. 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, regulators, or other equipment of Company caused by such material increase in Customer's connected load.

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 mains, Customer shall obtain from the proper owner or owners the necessary consent to the installation and maintenance in said premises and across such intervening property of Customer's piping and facilities required for the supply of gas 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.

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.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 97.2

TERMS AND CONDITIONS

Customer Responsibilities

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED (continued) T

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company.

LIABILITY

Customer assumes all responsibility for the gas service upon Customer's premises at and from the point of delivery of gas and for the pipes 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 gas, occasioned by such gas or said pipes 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 pipes, meters, and appurtenances supplied by Company for the rendition of gas service to its customers have a definite capacity. 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, regulators, or other equipment of Company caused by such material increase in Customer's connected load.

PERMITS

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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.

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The Customer Responsibilities section of the proposed LG&E Terms and Conditions is contained on four pages instead of the current three pages.

TERMS AND CONDITIONS

Customer Responsibilities

COMPANY-OWNED SERVICE LINES T

The Company will install, own, operate and maintain the service line at the premises of residential and commercial customers, if such premises are not connected to a Company main by a service line. With respect to residential and commercial customers that occupy premises already connected to a Company main by a service line that the Company has installed, repaired, or replaced, the Company shall be responsible for operating and maintaining the customer service line and when the Company determines that replacement of such customer service line is necessary the Company shall be responsible for installing the service line and shall thereafter own the service line.

Any customer accepting gas service under this section shall be deemed to have granted the Company an easement across his property for such service. No service line shall be installed across private property other than the premises of the building to be supplied with gas, except after special investigation and approval by the Company.

When the length of the service pipe required between the property line and the meter is 100 feet or less, the Company will assess no charge for the service pipe installation.

When the length of required service pipe exceeds 100 feet, the Company may require the applicant to contribute toward the cost of the service line installation an amount equal to the estimated cost per foot for each lineal foot of service beyond 100 feet. Contributions by customers toward the Company's cost of furnishing and installing service lines in accordance with this section are non-refundable.

In the event that the Company is required to undertake any excavation on a customer's property in connection with the installation, repair, maintenance or replacement of a service line, the Company shall make reasonable efforts to restore the property to its original condition pursuant to generally accepted utility standards for such construction operations.

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 98

TERMS AND CONDITIONS
Company Responsibilities

METERING
The gas 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 GAS
The point of delivery of gas supplied by Company shall be at the point where the gas passes from the pipes of Company's Service Connection into Customer's Service Line, irrespective of the location of the metering and regulating equipment.

COMPANY'S EQUIPMENT AND INSTALLATION
Company will furnish, install, and maintain at its expense the necessary Service Connection extending from its main to Customer's nearest property line, the location of which Service Connection shall be at the discretion of Company.

Company will furnish, install, and maintain at its expense the necessary meter, regulator, and connections appurtenant thereto, which shall be located in accordance with the discretion and judgment of Company. A suitable site or location for such meter and regulating equipment, together with an adequate protective enclosure for the same, if required, shall be provided by Customer. Title to the meter, regulator, and connections shall remain with 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 gas requirements.

COMPANY NOT LIABLE FOR INTERRUPTIONS
Company will exercise reasonable care and diligence in an endeavor to supply gas service continuously and without interruption, except as provided in the terms of certain rate schedules; however, Company does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay or failure of gas 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 gas service delivered at Company's property line, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 98

TERMS AND CONDITIONS

Company Responsibilities

METERING
The gas 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 GAS
The point of delivery of gas supplied by Company shall be at the point where the gas passes from the pipes of Company's Service Connection into Customer's Service Line, irrespective of the location of the metering and regulating equipment.

If the Service Line is owned by the Customer, the point of delivery of gas supplied by the Company shall be at the point where the gas passes from the pipes of Company's Service Connection into Customer's Service Line, irrespective of the location of the metering and regulation equipment. T

If the Service Line is owned by the Company, the point of delivery of gas supplied by the Company shall be at the point where the gas passes from the outlet of the meter to the Customer's yard line or house piping.

COMPANY'S EQUIPMENT AND INSTALLATION
The Company shall furnish, install, and maintain at its expense the necessary service connection. The location of this service connection will be made at the discretion and judgment of the Company. T

The Company will furnish, install, and maintain at its expense the necessary meter, regulator, and connections which will be located at or near the building, at the discretion or judgment of the Company. Suitable site or location for the meter, meter stand (including meter riser), and regulator and connections shall be provided by the Customer and title to this equipment shall remain in the Company with the right to install, operate, maintain, and remove same and no charge shall be made by the Customer for use of the premises as occupied or used. 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 a reasonable form of easement agreement, if requested by Company. T

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 gas requirements.

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TERMS AND CONDITIONS

Company Responsibilities

property of the Customer or of third persons resulting from the presence, use or abuse of gas on the Customer's premises or resulting from defects in or accidents to any of Customer's piping, 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 the Customer or any other party affected by the gas 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.

SPECIAL RULES FOR CUSTOMERS SERVED FROM HIGH PRESSURE MAINS, GAS TRANSMISSION MAINS, AND STORAGE GATHERING LINES

In order to ensure the integrity, safe operations, and reliability of the Company's gas system, these special rules apply to customers served from high pressure mains, gas transmission mains, and storage gathering lines.

When a customer requests service from a high pressure main, gas transmission main, or storage gathering line under Rate RGS, CGS, IGS, VFD, AAGS, or FT, Company shall determine, in its sole discretion, if service is justified, feasible, and consistent with good operating practice.

Upon approval by Company of a request by a customer (or group of customers) for service from a high pressure main, gas transmission main, or storage gathering line, then Company may charge the customer (or group of customers) in addition to the charges under the applicable rate schedule, the estimated installed cost of the tap, any regulation equipment, piping, and any other equipment or facilities determined by Company, in its sole discretion, to be necessary to provide such service consistent with good operating practice.

In no case, shall Company be obligated to provide service to customers served under Rate DGGS from a high pressure main, gas transmission main, or storage gathering line.

TERMS AND CONDITIONS

Company Responsibilities

COMPANY NOT LIABLE FOR INTERRUPTIONS T

Company will exercise reasonable care and diligence in an endeavor to supply gas service continuously and without interruption, except as provided in the terms of certain rate schedules; however, Company does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay or failure of gas 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 gas service delivered at Company's property line, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or property of the Customer or of third persons resulting from the presence, use or abuse of gas on the Customer's premises or resulting from defects in or accidents to any of Customer's piping, 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 the Customer or any other party affected by the gas 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.

OBLIGATION TO SERVE T

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company.

SPECIAL RULES FOR CUSTOMERS SERVED FROM HIGH PRESSURE MAINS, GAS TRANSMISSION MAINS, AND STORAGE GATHERING LINES

In order to ensure the integrity, safe operations, and reliability of the Company's gas system, these special rules apply to customers served from high pressure mains, gas transmission mains, and storage gathering lines.

T

The Company Responsibilities section of the proposed LG&E Terms and Conditions is contained on three pages instead of the current two pages.

TERMS AND CONDITIONS

Customer Responsibilities

When a customer requests service from a high pressure main, gas transmission main, or storage gathering line under Rate RGS, CGS, IGS, VFD, AAGS, or FT, Company shall determine, in its sole discretion, if service is justified, feasible, and consistent with good operating practice. T

Upon approval by Company of a request by a customer (or group of customers) for service from a high pressure main, gas transmission main, or storage gathering line, then Company may charge the customer (or group of customers) in addition to the charges under the applicable rate schedule, the estimated installed cost of the tap, any regulation equipment, piping, and any other equipment or facilities determined by Company, in its sole discretion, to be necessary to provide such service consistent with good operating practice.

In no case, shall Company be obligated to provide service to customers served under Rate DGGS from a high pressure main, gas transmission main, or storage gathering line.

TERMS AND CONDITIONS

Character of Service

HEATING VALUE

Company will normally supply natural gas having a heating value of approximately 1,000 Btu per cubic foot or as is otherwise supplied by the interstate pipeline(s) from which Company takes natural gas service. All gas received into the system of Company shall meet either of the applicable quality standards of the interstate pipeline delivering natural gas to Company or the lowest standard if there is more than one pipeline. Company reserves the right to refuse to accept gas from any entity whose gas does not meet those minimum standards. When it is necessary to supplement the supply of natural gas, Company reserves the right, at its discretion, to supplement its supply of natural gas with a mixture of vaporized liquefied petroleum gas and air.

STANDARD PRESSURE AND MEASUREMENT BASE

The standard distribution pressure of the gas supplied by Company is four ounces per square inch above atmospheric pressure.

Atmospheric pressure shall be assumed in all cases to be 14.5 pounds per square inch and temperature shall be assumed to be 60 degrees Fahrenheit; provided, however, Company reserves the right for billing purposes to correct as necessary the actual temperature to a 60 degree Fahrenheit basis in the case of large volume customers.

All gas measured at pressures higher than the standard pressure shall be converted to a pressure base of 14.73 pounds per square inch absolute for billing purposes.

TERMS AND CONDITIONS

Character of Service

HEATING VALUE

Company will normally supply natural gas having a heating value of approximately 1,000 Btu per cubic foot or as is otherwise supplied by the interstate pipeline(s) from which Company takes natural gas service. All gas received into the system of Company shall meet either of the applicable quality standards of the interstate pipeline delivering natural gas to Company or the lowest standard if there is more than one pipeline. Company reserves the right to refuse to accept gas from any entity whose gas does not meet those minimum standards. When it is necessary to supplement the supply of natural gas, Company reserves the right, at its discretion, to supplement its supply of natural gas with a mixture of vaporized liquefied petroleum gas and air.

STANDARD PRESSURE AND MEASUREMENT BASE

The standard distribution pressure of the gas supplied by Company is four ounces per square inch above atmospheric pressure.

Atmospheric pressure shall be assumed in all cases to be 14.5 pounds per square inch and temperature shall be assumed to be 60 degrees Fahrenheit; provided, however, Company reserves the right for billing purposes to correct as necessary the actual temperature to a 60 degree Fahrenheit basis in the case of large volume customers.

All gas measured at pressures higher than the standard pressure shall be converted to a pressure base of 14.73 pounds per square inch absolute for billing purposes.

Louisville Gas and Electric Company

P.S.C. Gas No. 8, 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 electric or gas 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.

Where Company serves a customer with both electric and gas service at the same service location, Company will render a combined bill. However, a residential customer may request, and Company will render, separate bills under the following conditions: (1) Customer is being threatened with disconnection for non-payment or has already been disconnected for that reason and (2) Customer would be able to pay either the gas or electric portion of his bill and thus retain one service.

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 the 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.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, 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 electric or gas 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.

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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 the 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.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 101.1

TERMS AND CONDITIONS

Billing

READING OF SEPARATE METERS NOT COMBINED

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

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 the Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of the Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, Company may contact Customer by telephone or in writing 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, or known leaks in the Customer's service line. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether it shows an average error greater than 2 percent fast or slow. Company will notify the customers of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 10(4) and (5). In addition to the annual monitoring, Company will immediately investigate usage deviations brought to its attention as a result of its on-going meter reading or billing processes or customer inquiry.

RESALE OF GAS

Gas service furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such gas to any other person, firm, or corporation on 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: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 101.1

TERMS AND CONDITIONS

Billing

READING OF SEPARATE METERS NOT COMBINED

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

CUSTOMER RATE MIGRATION T

Unless otherwise specified in the applicable rate schedule or rider, 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.

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 the Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of the Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, Company may contact Customer by telephone or in writing 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, or known leaks in the Customer's service line. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether it shows an average error greater than 2 percent fast or slow. Company will notify the customers of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 10(4) and (5). In addition to the annual monitoring, Company will immediately investigate usage deviations brought to its attention as a result of its on-going meter reading or billing processes or customer inquiry.

RESALE OF GAS

Gas service furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such gas to any other person, firm, or corporation on 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, 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 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.
5) The General Terms and Conditions regarding Deposits set forth above shall not apply to, and shall be superseded by, the deposit requirements set forth in Section 3 of the Terms and Conditions contained in Standard Rate Rider PS-TS (Sheet No. 60.1) and Standard Rate Rider PS-FT (Sheet No. 61.1).

RESIDENTIAL

1) Residential customers are those customers served under Residential Gas Service, Sheet No. 5.
2) The deposit for a residential customer is in the amount of $115.00, which is calculated in accordance with 807 KAR5:006, Section 7(1)(b). For combination gas and electric customers, the total deposit will be $250.00.
3) Company shall 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 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.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, 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 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.
5) The General Terms and Conditions regarding Deposits set forth above shall not apply to, and shall be superseded by, the deposit requirements set forth in Section 3 of the Special Terms T
and Conditions contained in Standard Rate Rider PS-TS-2 (Sheet No. 59.5), Standard Rate T
Rider PS-TS (Sheet No. 60.1), and Standard Rate Rider PS-FT (Sheet No. 61.1). T

RESIDENTIAL

1) Residential customers are those customers served under Residential Gas Service, Sheet No. 5.
2) The deposit for a residential customer is in the amount of $95.00, which is calculated in R
accordance with 807 KAR5:006, Section 7(1)(b). For combination gas and electric customers, the total deposit will be $230.00. R
3) Company shall 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 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.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 102.1

TERMS AND CONDITIONS

Deposits

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 7(1)(a).
2) For customers not meeting the parameters of GENERAL ¶ 2, 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 percent (10%), 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 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.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 102.1

TERMS AND CONDITIONS

Deposits

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 7(1)(a).
2) For customers not meeting the parameters of GENERAL ¶ 2, 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 percent (10%), 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 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.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 103

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to residential customers and to small commercial customers served under Rates CGS. Small business customers with combined gas and electric services must be served exclusively under General Service Rate GS for their electric service. 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 the plan at any time.

The budgeted amount will be determined by Company and will be based on one-twelfth of the 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 the customer's budget year. If actual usage indicates the customer's account will not be current with the final payment in the customer's budget year, the 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.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 103

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to residential customers and to small commercial customers served under Rates CGS. Small business customers with combined gas and electric services must be served exclusively under General Service Rate GS for their electric service. 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 the plan at any time.

The budgeted amount will be determined by Company and will be based on one-twelfth of the 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 the customer's budget year. If actual usage indicates the customer's account will not be current with the final payment in the customer's budget year, the 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.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 104
Canceling P.S.C. Gas No. 8, Original Sheet No. 104

TERMS AND CONDITIONS

Bill Format

LG&E
a PPL company

Customer Service: 1-800-331-7370 (M-F, 7 a.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: 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	$43.29

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 you account number available when calling to discuss your account.

ACCOUNT INFORMATION

Account Number:	3000-1111-2222
Account Name:	JOHN DOE
Service Address:	1234 Main St LOUISVILLE KY
Next Read Will Occur:	12/12/11 – 12/14/11
Date Bill Mailed:	11/16/11 (Meter Read Portion 10)

Averages for Billing Period	This Year	Last Year
Average Temperature	53°	58°
Number of Days Billed	28	0
Electric/kwh per day	9.1	0.00
Gas/ccf per day	1.4	0.00

BILLING SUMMARY

Previous Balance		23.07
Payment(s) Received 10/15 – 11/15		-23.07
Balance as of 11/15		0.00
Current Gas Charges	43.29	
Current Charges as of 11/15		43.29
Total Amount Due		43.29

GAS CHARGES

Rate Type: Residential Gas Service		Meter Reading Information	
Basic Service Charge	12.50	Meter # 444444	
Gas Distribution Charge ($0.22396 x 41 ccf)	9.18	Actual Reading on 11/11/11	6057
Gas Supply Component ($0.51602 x 41 ccf)	21.16	Previous Reading on 10/14/11	6016
Weather Normalization Adjustment ($0.22396 x 2.081 – ccf)	-0.47		
Other Charges For Above Rates		Current ccf Usage	41
		Meter Multiplier	1
Gas DSM ($0.01887 x 41.00 ccf)	0.77	Metered ccf Usage	41
Home Energy Assistance Fund Charge	0.15		
Total Gas Charges	$43.29		

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number	Payment Due Date	Pay This Amount	Pay This Amount 2 Days After Due Date	Winter Help Donation	Amount Enclosed
3000-1111-2222	11/28/11	$43.29	$45.45	$	$

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

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

LG&E
PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900062 48
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40026-8746

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 104

TERMS AND CONDITIONS

Bill Format

T

LG&E
a PPL company

Customer Service: 1-800-331-7370 (M-F, 7 a.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: 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
04/24/12	$50.88

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:	3000-1111-2222
Account Name:	JOHN DOE
Service Address:	1234 Main St LOUISVILLE KY
Next Read Will Occur:	05/08/12 – 05/10/12
Date Bill Mailed:	04/11/12 (Meter Read Portion 07)

Averages for Billing Period	This Year	Last Year
Average Temperature	63°	54°
Number of Days Billed	32	29
Gas/ccf per day	1.0	2.2

BILLING SUMMARY

Previous Balance		23.07
Payment(s) Received 03/10 – 4/11		-23.07
Balance as of 4/11		0.00
Current Gas Charges	50.88	
Current Charges as of 11/15		50.88
Total Amount Due		50.88

GAS CHARGES

Rate Type: Residential Gas Service		Meter Reading Information	
Basic Service Charge	12.50	Meter # 444444	
Gas Distribution Charge ($0.22396 x 35 ccf)	7.84	Actual Reading on 4/[illegible]/12	[illegible]
Gas Supply Component ($0.47423 x 35 ccf)	16.60	Previous Reading on [illegible]/12	[illegible]
Weather Normalization Adjustment ($0.22396 x 58.850 ccf)	13.18	Current ccf Usage	35
Gas DSM ($0.01709 x 35.00 ccf)	0.60	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.16	Metered ccf Usage	35
Total Gas Charges	$50.88		

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number	Payment Due Date	Pay This Amount	Pay This Amount 2 Days After Due Date	Winter Help Donation	Amount Enclosed
3000-1111-2222	04/24/12	$50.88	$53.42	$	$

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

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

LG&E
PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900062 48
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40026-8746

Service Address: 1234 Main 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, First Revision of Original Sheet No. 104.1
Canceling P.S.C. Gas No. 8, Original Sheet No. 104.1

TERMS AND CONDITIONS

Bill Format

Account Number 3000-1111-2222 Page 2

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date $2.17

IMPORTANT INFORMATION

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 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 LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 104.1

TERMS AND CONDITIONS

Bill Format

Account Number 3000-1111-2222 Page 2

T

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date $2.54

IMPORTANT INFORMATION

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 LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

Signature: ______________________

Date: ______________________

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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, Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format

Customer Service:	1-800-331-7370 (M-F, 7 a.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:	Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service:	www.lge-ku.com (24 hours a day)

a PPL company

DUE DATE	Pay This Amount
11/28/11	$71.82

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 you account number available when calling to discuss your account.

ACCOUNT INFORMATION

Account Number:	3000-1111-2222
Account Name:	JOHN DOE
Service Address:	1234 Main St LOUISVILLE KY
Next Read Will Occur:	12/12/11 – 12/14/11
Date Bill Mailed:	11/16/11 (Meter Read Portion 10)

Averages for Billing Period	This Year	Last Year
Average Temperature	53°	58°
Number of Days Billed	28	0
Electric/kwh per day	9.1	0.00
Gas/ccf per day	1.4	0.00

BILLING SUMMARY

Previous Balance		23.07
Payment(s) Received 10/15 -11/15		-23.07
Balance as of 11/15		0.00
Current Electric Charges	28.53	
Current Gas Charges	43.29	
Current Charges as of 11/15		71.82
Total Amount Due		71.82

ELECTRIC CHARGES

Rate Type: Residential Electric Service		**Meter Reading Information**	
Basic Service Charge	8.50	Meter # 704252	
Energy Charge ($0.07225 x 255.00 kwh)	18.42	Actual Reading on 11/11/11	257
		Previous Reading on 10/14/11	2
Other Charges For Above Rates			
Electric Fuel Adjustment ($0.00307 x 255 kwh)	0.78	Current kwh Usage	255
Electric DSM ($0.00244 x 255.00 kwh)	0.62	Meter Multiplier	1
Environmental Surcharge (0.210% x $28.32)	0.06	Metered kwh Usage	255
Home Energy Assistance Fund Charge	0.15		
Total Electric Charges	$28.53		

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

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	$71.82	$75.41	$	$

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

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

PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900082 4#
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40028-8746

Service Address: 1234 Main St

0200000000000000000000001245L00000011895000000000000000

TERMS AND CONDITIONS

Bill Format

T

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)

a PPL company

DATE DUE	AMOUNT DUE
04/24/12	$122.18

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:	3000-0216-5900-28
Account Name:	JOHN DOE
Service Address:	1234 ANYWHERE ST
Next Read Will Occur:	05/08/12 – 05/10/12
Date Bill Mailed:	04/11/12 (Meter Read Portion 07)

Averages for Billing Period	This Year	Last Year
Average Temperature	63 °	54 °
Number of Days Billed	32	29
Electric/kwh per day	24.3	19.8
Gas/ccf per day	1.0	2.2

BILLING SUMMARY

Previous Balance		102.30
Payment(s) as of 3/10 – 4/11		(102.30)
Balance as of 4/11		0.00
Electric Charges	71.30	
Gas Charges	50.88	
Utility Charges as of 08/20		122.18
Other Charges		
Total Amount Due		122.18

ELECTRIC CHARGES

Rate Type: Residential Electric Service		**Meter Reading Information**	
Basic Service Charge	8.50	Meter # 70000	
Energy Charge ($0.07242 x 778.00 kwh)	56.34	Actual Reading on 4/10/12	13124
Electric DSM ($0.00287 x 778 kwh)	2.23	Previous Reading on 3/9/12	12346
Electric Fuel Adjustment ($0.00472 x 778.00 kwh)	3.67	Current kwh Usage	778
Environmental Surcharge (0.560% x $70.74)	0.40	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.16	Metered kwh Usage	778
Total Electric Charges	$71.30		

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number	Payment Due Date	Amount Due by Due Date	Amount Due 5 Days After Due Date	Winter Help Donation	Amount Enclosed
3000-0216-5900-28	04/24/12	$122.18	$128.29	$	$

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

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

PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900082 4#
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40028-8746

Service Address: 1234 Main St

0200000000000000000000001245L00000011895000000000000000

TERMS AND CONDITIONS

Bill Format

Account Number 3000-1111-2222 Page 2

GAS CHARGES

Rate Type: Residential Gas Service		Meter Reading Information	
Basic Service Charge	12.50	Meter # 499779	
Gas Distribution Charge ($0.22396 x 41 ccf)	9.18	Actual Reading on 11/11/11	6057
Gas Supply Component ($0.51602 x 41 ccf)	21.16	Previous Reading on 10/14/11	6016
Weather Normalization Adjustment ($0.22396 x 2.081 - ccf)	-0.47	Current ccf Usage	41
		Meter Multiplier	1
Other Charges For Above Rates		Metered ccf Usage	41
Gas DSM ($0.01867 x 41.00 ccf)	0.77		
Home Energy Assistance Fund Charge	0.15		
Total Gas Charges	$43.29		

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date $3.59

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.

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 510 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 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 LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

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, Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format

T

Account Number 3000-0216-5900-28 Page 2

GAS CHARGES

Rate Type: Residential Gas Service		Meter Reading Information	
Basic Service Charge	12.50	Meter # 45678	
Gas Distribution Charge ($0.22396 x 35 ccf)	7.84	Actual Reading on 4/10/12	1922
Gas Supply Component ($0.47423 x 35 ccf)	16.60	Previous Reading on 3/9/12	1887
Weather Normalization Adjustment ($0.22396 x 58.850 ccf)	13.18	Current ccf Usage	35
Gas DSM ($0.01709 x 35.00 ccf)	0.60	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.16	Metered ccf Usage	35
Total Gas Charges	$50.88		

BILLING INFORMATION

Late Charge to be Assessed 3 days After Due Date $6.11

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 1,558 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 LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

Signature: ______________________________

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

Louisville Gas and Electric Company

P.S.C. Gas No. 8, 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 to 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 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 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, 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 to 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 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 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, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 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 the 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.

Louisville Gas and Electric Company

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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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.

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 106

TERMS AND CONDITIONS

Gas Main Extension Rules

1. Company will extend its gas distribution mains at its own expense for a distance of one hundred (100) feet to each bona-fide applicant who agrees in writing to take service within one (1) year after the extension is completed and who has a suitable Customer's Service Line installed and ready for connection provided the following criteria are met:
   a) The existing main is of sufficient capacity to properly supply the additional customer(s);
   b) The customer(s) contracts to use gas on a continuous basis for one (1) year or more; and,
   c) The potential consumption and revenue will be of such amount and permanence as to warrant the capital expenditures involved to make the investment economically feasible.

2. Company will extend its gas mains in excess of the above distance provided the applicant for service advances to Company an amount equal to the estimated cost of such excess portion of the extension. Company shall have the right to determine the length of the extension and to specify the pipe size and location of the extension, as well as the timing of its construction.

3. Where funds were advanced in accordance with paragraph 2 for extensions into developed residential neighborhoods and notwithstanding paragraph 1, any customer that subsequently connects to the main during a ten-year period from the effective date of the main extension contract shall advance to Company a pro rata share of the cost of the extension over 100 feet per connected customer.

4. For each new year-round customer connected to an extension in accordance with paragraph 3, Company will refund to the previous applicant(s) who advanced funds an amount equal to the difference between the refundable amount advanced and the amount of the advance so determined for the new applicant.

5. Company will extend its gas mains to serve a proposed real estate subdivision provided the applicant for such extension advances to Company an amount equal to the estimated cost of the total extension. Company shall have the right to determine the length of the extension and to specify the pipe size and the location of the extension, as well as the timing of its construction.

6. For each new year-round customer actually connected to the extension within a ten-year period following the effective date of the gas main extension contract, but not to extensions or laterals therefrom, Company will refund to applicant(s) who advanced funds in accordance with paragraph 5 above an amount equal to 100 times the average unit cost per foot of extension advanced by such applicant(s); provided that such refunds shall not exceed, in the aggregate, the amount originally advanced to Company.

7. Company will install at its own expense a service pipe of suitable capacity extending from its gas main to the customer's property line beyond which point all necessary piping shall be installed by and at the expense of the customer and in a manner acceptable to Company.

Date of Issue: August 6, 2010
Date Effective: August 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 106

TERMS AND CONDITIONS

Gas Main Extension Rules

1. Company will extend its gas distribution mains at its own expense for a distance of one hundred (100) feet to each bona-fide applicant who agrees in writing to take service within one (1) year after the extension is completed and who has a suitable Customer's Service Line installed and ready for connection provided the following criteria are met:
   a) The existing main is of sufficient capacity to properly supply the additional customer(s);
   b) The customer(s) contracts to use gas on a continuous basis for one (1) year or more; and,
   c) The potential consumption and revenue will be of such amount and permanence as to warrant the capital expenditures involved to make the investment economically feasible.

2. Company will extend its gas mains in excess of the above distance provided the applicant for service advances to Company an amount equal to the estimated cost of such excess portion of the extension. Company shall have the right to determine the length of the extension and to specify the pipe size and location of the extension, as well as the timing of its construction.

3. Where funds were advanced in accordance with paragraph 2 for extensions into developed residential neighborhoods and notwithstanding paragraph 1, any customer that subsequently connects to the main during a ten-year period from the effective date of the main extension contract shall advance to Company a pro rata share of the cost of the extension over 100 feet per connected customer.

4. For each new year-round customer connected to an extension in accordance with paragraph 3, Company will refund to the previous applicant(s) who advanced funds an amount equal to the difference between the refundable amount advanced and the amount of the advance so determined for the new applicant.

5. Company will extend its gas mains to serve a proposed real estate subdivision provided the applicant for such extension advances to Company an amount equal to the estimated cost of the total extension. Company shall have the right to determine the length of the extension and to specify the pipe size and the location of the extension, as well as the timing of its construction.

6. For each new year-round customer actually connected to the extension within a ten-year period following the effective date of the gas main extension contract, but not to extensions or laterals therefrom, Company will refund to applicant(s) who advanced funds in accordance with paragraph 5 above an amount equal to 100 times the average unit cost per foot of extension advanced by such applicant(s); provided that such refunds shall not exceed, in the aggregate, the amount originally advanced to Company.

7. Company will install at its own expense a service pipe of suitable capacity extending from its gas main to the customer's property line beyond which point all necessary piping shall be installed by and at the expense of the customer and in a manner acceptable to Company.

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

Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

Gas Main Extension Rules

8. Company will install at its own expense the necessary meter together with the regulator required to convert from medium pressure to service pressure. When a high pressure gas line is tapped to serve a customer or group of customers, Company may charge the customer or customers for the estimated installed cost of the tap, any regulation equipment, piping, and any other equipment or facilities determined by Company, in its sole discretion, to be necessary to provide such service consistent with good operating practice.

9. In the event Company is required to make a further extension of its mains to serve a customer, Company reserves the right to tap any extension constructed under these rules and to make connections from such additional extensions without application of the refunds referred to in paragraph 4 or 6 above.

10. The title to all extensions herein provided for, together with all necessary rights-of-way, permits and easements, shall be and remain in Company.

11. Company shall not be obligated to make service connections or to extend its gas mains in cases where such extensions or connections, in the sole judgment of Company would be infeasible, impractical, or contrary to good operating practice, or where such extensions are not in accordance with the terms of the applicable rate schedule.

TERMS AND CONDITIONS

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Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 107

TERMS AND CONDITIONS

Gas Service Restrictions

By Order dated September 5, 1973, in Case Nos. 5829 and 5839, the Public Service Commission of Kentucky authorized Company to incorporate in its gas tariff restrictions on the supply of gas service, occasioned by the inadequacy of gas supplies to meet customer demands. These restrictions have been modified from time to time by tariff filings authorized or approved by the Commission. Uncertainty as to future gas supply makes it necessary that Company continue to exercise control over the addition of gas loads to its system, as set forth in these rules.

1. **GENERAL.** Except as specifically provided in these rules, Company will not (a) initiate service to any new customer, location, or service point; (b) permit any commercial customer (including any governmental agency or institution) or any industrial customer to increase its connected load or to expand its gas requirements in any manner; or (c) permit any customer to change to another rate schedule for the purpose of obtaining a higher priority under Company's Tariff.

2. **NEW CUSTOMERS.** Until further notice, Company will accept applications for gas service to new customers as set forth below. Main extensions will be made in accordance with the Gas Main Extension Rules contained in this Tariff.

   (a) **FOR SERVICE UNDER RATES RGS, VFD, CGS, DGGS, IGS, and FT.** Single family dwelling units individually metered. Commercial and industrial customers and multi-family residences served through a single meter. Company will have the right to limit the total connected load to a maximum of 8,000 cubic feet per hour, when in Company's judgment such is necessary in order to enable it to continue to supply reliable service to existing customers.

   (b) **FOR SERVICE UNDER OTHER RATE SCHEDULES.** Company may undertake to serve new customers with requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS, IGS, and FT when in its judgment actual and potential gas supplies are sufficient to enable it to do so. Company will designate the applicable rate schedule under which such service will be supplied.

3. **INCREASE IN SERVICE TO EXISTING CUSTOMERS.** Until further notice, Company will, upon application, permit increases in the connected gas load or the gas usage of commercial and industrial customers existing as of the effective date of these rules, as follows:

   (a) **ADDITIONAL SERVICE UNDER RATES RGS, VFD, CGS, DGGS, IGS, and FT.** Company will permit the addition of connected gas loads under Rates RGS, VFD, CGS, DGGS, IGS, and FT. Company will have the right to limit the total connected load to a maximum of 8,000 cubic feet per hour, when in Company's judgment such is necessary in order to enable it to continue to supply reliable service to existing customers.

   (b) **ADDITIONAL SERVICE UNDER OTHER RATE SCHEDULES.** Company may undertake to serve existing customers with additional requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS, IGS, and FT when in its judgment actual and potential gas supplies are sufficient to enable it to do so. Company will designate the applicable rate schedule under which such service will be supplied.

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 107

TERMS AND CONDITIONS

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TERMS AND CONDITIONS

Gas Service Restrictions

4. **LOAD ADDITIONS TO BE AGGREGATED.** Limitations on new or additional gas loads as specified herein refer to the aggregate of loads added subsequent to the effective date of these rules, and not to individual increments made from time to time.

5. **VOLUMES OF GAS USAGE.** Daily and monthly volumes of gas usage may be established or increased to reflect additions of connected load or increased usage of connected load existing as of the effective date of these rules. For customers subject to curtailment under Company's Curtailment Rules, Monthly Base Period Volumes will be established or adjusted accordingly.

6. **TRANSFERS BETWEEN LOCATIONS.** Company may permit any customer to transfer his own gas entitlement from one location to another; provided, however, that transfers of service cannot be aggregated so as to exceed the limitations on connected load set forth in Paragraphs 2 and 3 above with respect to Rates RGS, VFD, CGS, DGGS, IGS, and FT.

7. **PRIORITY CONSIDERATIONS.** If at any time, Company is required to select among applicants for service as provided for in Paragraphs 2(b) or 3(b) above, it will, to the extent practicable, observe the following priorities in the order named:

   (a) Schools, hospitals and similar institutions.
   (b) Other commercial establishments.
   (c) Industrial process and feedstock uses.
   (d) Other industrial applications.

8. **LAPSE OF APPLICATIONS.** If any applicant for new or increased service under these rules is not ready to take such service within twelve (12) months from the date of application, such application shall be void. Any reapplication shall be subject to Company's rules in effect at the time thereof.

9. Applicants may make application for gas service beyond that provided for in these rules, to be initiated at such time as these rules may be terminated or modified so as to enable Company to provide the service applied for. Company will file such applications in the order of receipt and dispose of them as circumstances dictate.

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Louisville Gas and Electric Company

TERMS AND CONDITIONS

Curtailment Rules

These rules are established to govern Company's available supply of gas to sales and transportation customers during periods of shortage or substantial reduction in the gas available to Company. These rules are designed to provide for curtailment or discontinuance of service made necessary by a deficiency in gas supply, capacity, or unforeseen emergency circumstances. These rules are designed to enable Company to continue to supply reliable gas service for residential and other human welfare purposes. These rules shall apply and continue in effect until lawfully modified or superseded under the regulatory jurisdiction of the Public Service Commission of Kentucky.

1. **DEFINITIONS** (for purposes of these Rules).

   COMMERCIAL CUSTOMERS: Customers engaged primarily in the sale of goods or services, including institutions and local, state and Federal governmental agencies, for uses other than those involving manufacturing as further described in Rate CGS.

   HUMAN NEEDS: Residential and other customers whose facilities are used for residential dwellings on either a permanent or temporary basis or a facility providing critical emergency services (including, but not limited to, apartment buildings, correctional institutions, hospitals, nursing homes, assisted living facilities, hotels, motels, fire department stations, police stations, national guard facilities, and emergency response agency facilities).

   INDUSTRIAL CUSTOMERS: Customers engaged primarily in a process or processes which create or change raw or unfinished materials into another form or product, including, but not limited to, the generation of electric power as further described in Rate IGS and Rate DGGS.

   SMALL INDUSTRIAL CUSTOMER: Any industrial customer whose aggregate of twelve Monthly Base Period Volumes is 10,000 Mcf or less.

   LARGE INDUSTRIAL CUSTOMER: Any industrial customer whose aggregate of twelve Monthly Base Period Volumes exceeds 10,000 Mcf.

   PILOT LIGHT REQUIREMENTS: Gas used on either a continuous or intermittent basis only for the ignition of the fuel in the main burner; does not include any gas used to preheat or atomize solid or liquid fuels.

   BASE PERIOD: The twelve (12) months ending on the October 31 preceding the calendar year which is the subject of the implementation of any curtailments hereunder.

   MONTHLY BASE PERIOD VOLUMES: Monthly volumes assigned to each customer determined from its gas consumption during the Base Period.

   AUTHORIZED MONTHLY VOLUME: The volume of gas authorized to be taken during a month and determined by deducting from the Monthly Base Period Volume the curtailment amount applicable for the month.

Some Customers may have usage falling within more than one (1) of the above categories; as such, these customers may be required to segregate their total usage accordingly.

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   BASE PERIOD: The twelve (12) months ending on the October 31 preceding the calendar year which is the subject of the implementation of any curtailments hereunder.

   MONTHLY BASE PERIOD VOLUMES: Monthly volumes assigned to each customer determined from its gas consumption (including sales and transportation volumes) during the Base Period. T

   AUTHORIZED MONTHLY VOLUME: The volume of gas authorized to be taken during a month and determined by deducting from the Monthly Base Period Volume the curtailment amount applicable for the month. 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 8, Original Sheet No. 108.1

TERMS AND CONDITIONS

Curtailment Rules

2. **COMBINATION OF AUTHORIZED MONTHLY VOLUMES.** Subject to a written application by a customer and acceptance thereof by Company, Company may permit any customer served through more than one point of delivery at any location, or any person, corporation or entity served with gas at more than one location, to take gas through the points or at the locations of its choosing, provided that the gas so taken will not exceed the combined Authorized Monthly Volumes applicable to such points of delivery, and provided that only volumes purchased under rate schedules subject to Pro-Rata Curtailment may be so combined. Gas taken through each individual point of delivery will be billed at the rate applicable to such point of delivery.

   The right to combine Authorized Monthly Volumes as herein described is limited to individual customers or individual persons, corporations or entities and such right will not extend to similar combinations between or among unrelated customers. Nor shall such combinations be employed by any customer for the purpose of obtaining a lower overall cost of gas.

   Provided, however, in the case of Industrial Customers provided with sales service under Rate IGS or Special Contracts, which have requested and received approval to combine Authorized Monthly Volumes, Monthly Base Period Volumes for such combined Industrial Customers must aggregate to not less than 10,000 Mcf for a twelve-month period and such combination shall be treated as a Large Industrial Customer for the purpose of implementing either Pro-Rata or Emergency Curtailment.

   For the purpose of assessment of penalties, the point of delivery will be considered on a combined basis, so that the actual combined takes will be measured against combined Authorized Monthly Volumes. It will be the responsibility of any applicant for this treatment to advise Company in writing as to the party or entity to be held accountable for the payment of such penalty.

3. **PRO-RATA CURTAILMENT.** In order to meet seasonal and daily sendout requirements, to preserve underground storage deliverability, and to provide for adequate and timely underground storage injections, Company will implement pro-rata curtailment with respect to the classes of customers here listed:

   (a) All customers served under Rate AAGS.
   (b) Large Industrial Customers provided with sales service under Rate IGS or Special Contracts.

   Company will assign Monthly Base Period Volumes to each customer in the above two classes. Except in the case of an Emergency Curtailment, Company will provide as much notice as practicable to each of these customers that curtailment is being implemented. Such notice will include the percentage curtailment applicable to customer's Monthly Base Period Volume and the Authorized Monthly Volume such customer is authorized to take during said billing period.

   Except in the case of Emergency Curtailment, such Pro-Rata Curtailment may only be implemented after Company issues an Operational Flow Order to customers served under Rate FT and takes similar actions applicable to transportation customers served under Special Contracts.

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TERMS AND CONDITIONS

Curtailment Rules

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   The right to combine Authorized Monthly Volumes as herein described is limited to individual customers or individual persons, corporations or entities and such right will not extend to similar combinations between or among unrelated customers. Nor shall such combinations be employed by any customer for the purpose of obtaining a lower overall cost of gas.

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   (a) All customers served under Rate AAGS.
   (b) Large Industrial Customers provided with sales service under Rate IGS or Special Contracts.

   Company will assign Monthly Base Period Volumes to each customer in the above two classes. Except in the case of an Emergency Curtailment, Company will provide as much notice as practicable to each of these customers that curtailment is being implemented. Such notice will include the percentage curtailment applicable to customer's Monthly Base Period Volume and the Authorized Monthly Volume such customer is authorized to take during said billing period.

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TERMS AND CONDITIONS

Curtailment Rules

During each month, Pro-Rata Curtailment will be first applied to Rate AAGS customers until such curtailment reaches 100% of Monthly Base Period Volumes (allowing, however, for continuation of Pilot Light Requirements used in connection with alternate fuels). When Rate AAGS customers are 100% curtailed, any additional curtailment required will be apportioned at a uniform percentage to other customers subject to pro-rata curtailment under this Section 3.

4. **EMERGENCY CURTAILMENT.** In the event of an emergency, Company will initiate the following actions, individually or in combination, in the order necessary as time permits so that service may continue to be supplied for residential and other human health, safety and welfare needs.

   (1) Issue Operational Flow Orders to customers served under Rate FT, and take similar actions applicable to transportation customers served under Special Contracts. Customers that fail to comply with Operational Flow Orders will be required to discontinue the use of natural gas.

   (2) Discontinue service to customers served under Rate AAGS.

   (3) Implement curtailment of all or a portion of the gas usage by Large Industrial Customers served under either Rate IGS or Special Contracts for gas sales service.

   (4) Once curtailment in level 3 (above) has reached 100% of usage (excluding Pilot Light Requirements), implement curtailment of all or a portion of gas usage to the remaining Small Industrial and non-human needs commercial use customers.

   (5) Once curtailment of customers in level 4 (above) has reached 100% of usage (excluding Pilot Light Requirements), request reduction of gas usage by human needs commercial, residential, and other human needs customers.

   (6) Implement forced curtailment of gas usage through the isolation of gas distribution load centers from the gas distribution system network.

5. **PENALTY CHARGES.** Company may, in its sole discretion, apply a penalty for all gas taken during a period of either Pro-Rata or Emergency Curtailment.

   Any customer subject to Pro-Rata curtailment in accordance with Section 3 above, who at the end of a month has taken gas in excess of its Authorized Monthly Volumes (excluding Pilot Light Requirements where applicable) for such month, may, in the sole discretion of Company, be subject to a penalty charge applicable to such excess takes of gas at the rate of $15.00 per Mcf plus the highest daily mid-point price posted in "Gas Daily" for Dominion-South Point during each month of the period of curtailment, such penalty to be in addition to the established rate for service.

   Any customer subject to Emergency Curtailment in accordance with Section 4 above, who uses quantities of gas in excess of authorized quantities (excluding Pilot Light Requirements where applicable) during a period of such Emergency Curtailment, may, in the sole discretion of

TERMS AND CONDITIONS

Curtailment Rules

Except in the case of Emergency Curtailment, such Pro-Rata Curtailment may only be implemented after Company issues an Operational Flow Order to customers served under Rate FT and takes similar actions applicable to transportation customers served under Special Contracts. T T T T

During each month, Pro-Rata Curtailment will be first applied to Rate AAGS customers until such curtailment reaches 100% of Monthly Base Period Volumes (allowing, however, for continuation of Pilot Light Requirements used in connection with alternate fuels). When Rate AAGS customers are 100% curtailed, any additional curtailment required will be apportioned at a uniform percentage to other customers subject to pro-rata curtailment under this Section 3.

4. **EMERGENCY CURTAILMENT.** In the event of an emergency, Company will initiate the following actions, individually or in combination, in the order necessary as time permits so that service may continue to be supplied for residential and other human health, safety and welfare needs.

   (1) Issue Operational Flow Orders to customers served under Rate FT, and take similar actions applicable to transportation customers served under Special Contracts. Customers that fail to comply with Operational Flow Orders will be required to discontinue the use of natural gas.

   (2) Issue Action Alerts to Pool Managers under Rider PS-TS-2 serving customers under Rider TS-2, and take similar actions applicable to transportation customers served under Special Contracts. Customers of Pool Managers that fail to comply with Action Alerts may be required to terminate service under Rider PS-TS-2 and Rider TS-2 and return to firm sales service. T

   (3) Discontinue service to customers served under Rate AAGS. T

   (4) Implement curtailment of all or a portion of the gas usage by Large Industrial Customers served under either Rate IGS or Special Contracts for gas sales service. T

   (5) Once curtailment in level 4 (above) has reached 100% of usage (excluding Pilot Light Requirements), implement curtailment of all or a portion of gas usage to the remaining Small Industrial and non-human needs commercial use customers. T

   (6) Company may request that transportation customers served under Rate FT and Special Contracts allow Company's use of customer-owned gas to supply higher priority end-use customers. Company shall negotiate compensation for such gas with any customer that complies with such request. T T T T

   (7) Once curtailment of customers in level 5 (above) has reached 100% of usage (excluding Pilot Light Requirements), request reduction of gas usage by human needs commercial, residential, and other human needs customers. T

   (8) Implement forced curtailment of gas usage through the isolation of gas distribution load centers from the gas distribution system network. T

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Company, be subject to a penalty charge applicable to such unauthorized takes of gas at the rate of $15.00 per Mcf plus the highest daily mid-point price posted in "Gas Daily" for Dominion-South Point during each month of the period of curtailment, such penalty to be in addition to the established rate for service.

The payment of penalty charges for takes of gas in excess of Authorized Monthly Volumes or authorized quantities shall not be considered as giving any customer the right to make unauthorized takes of gas, nor shall such penalty charges be considered as a substitute for any other remedy available to Company.

Company shall return to all customers through Company's Gas Supply Clause any penalty charges collected from customers under this Section 5 net of any penalty charges incurred from Company's supplier(s).

6. **DISCONTINUANCE OF SERVICE.** If any customer subject to curtailment under these rules fails to limit its use of gas as provided for herein, then Company shall have the right to immediately discontinue all gas supply to such customer.

5. **PENALTY CHARGES.** Company may, in its sole discretion, apply a penalty for all gas taken during a period of either Pro-Rata or Emergency Curtailment. T

   Any customer subject to Pro-Rata curtailment in accordance with Section 3 above, who at the end of a month has taken gas in excess of its Authorized Monthly Volumes (excluding Pilot Light Requirements where applicable) for such month, may, in the sole discretion of Company, be subject to a penalty charge applicable to such excess takes of gas at the rate of $15.00 per Mcf plus the highest daily mid-point price posted in "*Platts Gas Daily*" for Dominion-South Point during each month of the period of curtailment, such penalty to be in addition to the established rate for service.

   Any customer subject to Emergency Curtailment in accordance with Section 4 above, who uses quantities of gas in excess of authorized quantities (excluding Pilot Light Requirements where applicable) during a period of such Emergency Curtailment, may, in the sole discretion of Company, be subject to a penalty charge applicable to such unauthorized takes of gas at the rate of $15.00 per Mcf plus the highest daily mid-point price posted in "*Platts Gas Daily*" for Dominion-South Point during each month of the period of curtailment, such penalty to be in addition to the established rate for service. T

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   Company shall return to all customers through Company's Gas Supply Clause any penalty charges collected from customers under this Section 5 net of any penalty charges incurred from Company's supplier(s).

6. **DISCONTINUANCE OF SERVICE.** If any customer subject to curtailment under these rules fails to limit its use of gas as provided for herein, then Company shall have the right to immediately discontinue all gas supply to such customer.

Louisville Gas and Electric Company
Case No. 2012-00222
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 LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, APPROVAL OF OWNERSHIP OF GAS SERVICE LINES AND RISERS, AND A GAS LINE SURCHARGE	**))))))))**	**CASE NO. 2012-00222**

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 Louisville Gas and Electric Company ("LG&E" or "Company"), a utility furnishing retail electric and gas 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 and gas rates, terms, and conditions of LG&E, and that notice to the public of the issuing of the same is being given 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 701 South Ninth Street, Louisville, KY 40203 and that the same will be kept open to public inspection at said office 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 LG&E'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, LG&E 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, LG&E posted on its Internet website a complete copy of LG&E'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 Louisville Gas and Electric Company seeks approval by the Public Service Commission, Frankfort, Kentucky of an adjustment of electric and gas 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.

LG&E CURRENT AND PROPOSED ELECTRIC RATES

Residential Service - Rate RS

	Current	Proposed
Basic Service Charge per Month:	$8.50	$13.00
Energy Charge per kWh:	$0.07242	$ 0.07513

Volunteer Fire Department Service - Rate VFD

	Current	Proposed
Basic Service Charge per Month:	$8.50	$13.00
Energy Charge per kWh:	$0.07242	$ 0.07513

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:	$ 0.08240	$ 0.08624

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.

Power Service – Rate PS

Secondary Service	Current	Proposed
Basic Service Charge (per Month)	$90.00	$90.00
Energy Charge (per kWh)	$ 0.03421	$ 0.03615
Demand Charge (per kW per month of billing demand)		
Summer Rate (May through September)	$15.39	$16.20
Winter Rate (All Other Months)	$13.14	$13.75

Primary Service	Current	Proposed
Basic Service Charge (per Month)	$90.00	$125.00
Energy Charge (per kWh)	$ 0.03421	$ 0.03416
Demand Charge (per kW per month of billing demand)		
Summer Rate (May through September)	$13.55	$13.54
Winter Rate (All Other Months)	$11.31	$11.31

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.

Industrial Time-of-Day Secondary Service Rate ITODS

Current Rate

Basic Service Charge (per Month)	$300.00
Energy Charge (per kWh)	$ 0.02984
Maximum Load Charge (per kW per month)	
Peak Demand Period	$ 5.18
Intermediate Demand Period	$ 3.68
Base Demand Period	$ 5.46

Proposed Rate (Industrial Time-of-Day Secondary Service Rate ITODS is proposed to be combined with Commercial Time-of-Day Secondary Service Rate CTODS. The new combined rate will be named Time-of-Day Secondary Service Rate TODS.)

Commercial Time-of-Day Secondary Service Rate CTODS

Current Rate

Basic Service Charge (per Month)	$200.00
Energy Charge (per kWh)	$ 0.03383
Maximum Load Charge (per kW per month)	
Peak Demand Period	$ 5.78
Intermediate Demand Period	$ 4.25
Base Demand Period	$ 3.76

Proposed Rate (Commercial Time-of-Day Secondary Service Rate CTODS is proposed to be combined with Industrial Time-of-Day Secondary Service Rate ITODS. The new combined rate will be named Time-of-Day Secondary Service Rate TODS.)

Proposed Time-of-Day Secondary Service Rate TODS

Basic Service Charge (per Month)	$200.00
Energy Charge (per kWh)	$ 0.03580
Maximum Load Charge (per kW per month)	
Peak Demand Period	$ 6.15
Intermediate Demand Period	$ 4.52
Base Demand Period	$ 4.00

Availability of Service: Proposed combined schedule clarifies that demand component of eligibility for taking service under this rate will be calculated on 12-month average of monthly maximum loads.

Industrial Time-of-Day Primary Service Rate ITODP

Current Rate

Basic Service Charge (per Month)	$300.00
Energy Charge (per kWh)	$ 0.02984
Demand Charge (per kW per month)	
Basic Demand	$ 4.17
Peak Demand	
Summer Peak Period	$ 10.12
Winter Peak Period	$ 7.32

Basic Demand Charges are applicable to the highest average load in kilowatts recorded during any 15-minute interval of the billing period and Peak Demand Charges are applicable to the highest average load in kilowatts recorded during any 15-minute interval of the peak period, as defined herein, in the monthly billing period, but not less than 50% of the maximum demands similarly determined for any of the four (4) billing periods of June through September within the eleven (11) preceding months.

SUMMER PEAK PERIOD is defined as weekdays from 10 A.M. to 9 P.M, Eastern Standard Time, during the four (4) billing periods of June through September.

WINTER PEAK PERIOD is defined as weekdays from 8 A.M. to 10 P.M., Eastern Standard Time, during the eight (8) billing periods of October through May.

Proposed Rate (Industrial Time-of-Day Primary Service Rate ITODP is proposed to be combined with Commercial Time-of-Day Primary Service Rate CTODP. The new combined rate will be named Time-of-Day Primary Service Rate TODP.)

Commercial Time-of-Day Primary Service Rate CTODP

Current Rate

Basic Service Charge (per Month)	$200.00
Energy Charge (per kWh)	$ 0.03383
Maximum Load Charge (per kVA per month)	
Peak Demand Period	$ 5.65
Intermediate Demand Period	$ 4.15
Base Demand Period	$ 2.59

Proposed Rate (Commercial Time-of-Day Primary Service Rate CTODP is proposed to be combined with Industrial Time-of-Day Primary Service Rate ITODP. The new combined rate will be named Time-of-Day Primary Service Rate TODP.)

Proposed Time-of-Day Primary Service Rate TODP

Availability of Service: Proposed combined schedule clarifies that demand component of eligibility for taking service under this rate will be calculated on 12-month average of monthly maximum loads

Basic Service Charge (per Month)	$300.00
Energy Charge (per kWh)	$ 0.03028
Maximum Load Charge (per kVA per month)	
Peak Demand Period	$ 5.59
Intermediate Demand Period	$ 3.95

Base Demand Period	$ 3.72

Summer Period - Five Billing Periods of May through September

Weekdays: Base (all hours), Interm. (10am-10pm), Peak (1pm-7pm)

Weekends: Base (all hours), Interm. (N/A), Peak (N/A)

Winter Period - All Other Months

Weekdays: Base (all hours), Interm (6am-10pm), Peak (6am-12noon)

Weekends: Base (all hours), Interm. (N/A), Peak (N/A)

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.

Retail Transmission Service - Rate RTS

	Current	**Proposed**
Basic Service Charge (per Month)	$500.00	$750.00
Energy Charge (per kWh)	$ 0.02984	$ 0.03228
Maximum Load Charge (per kVA per month)		
Peak Demand Period	$ 4.32	$ 4.64
Intermediate Demand Period	$ 2.82	$ 3.03
Base Demand Period	$ 2.57	$ 2.76

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)	$ 0.03710	$ 0.03228
Maximum Load Charge (per kVA per month)		
Peak Demand Period	$ 2.71	$ 3.03
Intermediate Demand Period	$ 1.71	$ 1.92
Base Demand Period	$ 1.71	$ 1.90

Transmission Service	**Current**	**Proposed**
Basic Service Charge (per Month)	$500.00	$750.00
Energy Charge (per kWh)	$ 0.03428	$ 0.03228
Maximum Load Charge (per kVA per month)		
Peak Demand Period	$ 2.71	$ 3.03
Intermediate Demand Period	$ 1.71	$ 1.92
Base Demand Period	$ 0.96	$ 1.15

Current:
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,
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 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.

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,
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.

Lighting Service - Rate LS
and
Restricted Lighting Service – Rate RLS

Lighting Service (Rate LS – Sheet No. 35) and Restricted Lighting Services (Rate RLS – Sheet No. 36) are being reorganized with various lighting offerings being consolidated into like kind. Lighting Service (Rate LS) will be a consolidation of lighting fixtures currently offered. Restricted Lighting Service (Rate RLS) 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			
452 Cobra Head, 16000 Lum. Fixt. Only			$12.48

Cobra Head, 16000L OHHP	LS 35.2	$11.62	
150W HPS Outdoor Lt.	RLS 36	$12.63	
150W HPS Outdoor Lt. after 1/1/91	RLS 36	$12.63	
150W HPS Outdoor Lt.	RLS 36.3	$11.52	
150W HPS Outdoor Lt. after 1/1/91	RLS 36.3	$11.52	
453 Cobra Head, 28500 Lum. Fixt. Only			$14.57
Cobra Head, 28500L OHHP	LS 35.2	$13.44	
250W HPS Outdoor Lt.	RLS 36	$14.97	
250W HPS Outdoor Lt. after 1/1/91	RLS 36	$14.97	
250W HPS Outdoor Lt.	RLS 36.3	$13.86	
250W HPS Outdoor Lt. after 1/1/91	RLS 36.3	$13.86	
454 Cobra Head, 50000 Lum. Fixt. Only			$16.58
Cobra Head, 50000L OHHP	LS 35.2	$18.53	
400W HPS Outdoor Lt.	RLS 36	$16.34	
400W HPS Outdoor Lt. after 1/1/91	RLS 36	$16.34	
400W HPS Outdoor Lt.	RLS 36.3	$14.97	
400W HPS Outdoor Lt. after 1/1/91	RLS 36.3	$14.97	
455 Directional, 16000 Lum. Fixt. Only			$13.44
Directional Flood, 16000L OHHP	LS 35.2	$13.23	
150W HPS Flood Lt.	RLS 36	$12.63	
150W HPS Flood Lt. after 1/1/91	RLS 36	$12.63	
150W HPS Flood Lt.	RLS 36.3	$13.85	
150W HPS Flood Lt. after 1/1/91	RLS 36.3	$11.52	
456 Directional, 50000 Lum. Fixt. Only			$17.41
Directional Flood, 50000L OHHP	LS 35.2	$19.50	
400W HPS Flood Lt.	RLS 36	$16.34	
400W HPS Flood Lt. after 1/1/91	RLS 36	$16.34	
400W HPS Flood Lt.	RLS 36.3	$14.97	
400W HPS Flood Lt. after 1/1/91	RLS 36.3	$14.97	
457 Open Bottom, 9500 Lum. Fixt. Only			$10.60
Open Bottom, 9500L OHHP	LS 35.2	$10.40	
100W HPS Outdoor Lt.	RLS 36	$10.00	
100W HPS Outdoor Lt. after 1/1/91	RLS 36	$10.00	
100W HPS Outdoor Lt.	RLS 36.3	$ 9.70	
100W HPS Outdoor Lt. after 1/1/91	RLS 36.3	$ 9.70	
Metal Halide			
470 Directional, 12000 Lum. Fixt. Only			$12.47
Directional Fixture Only, 12000	LS 35.3	$11.85	
473 Directional, 32000 Lum. Fixt. Only			$18.09
Directional Fixture Only, 32000	LS 35.3	$17.19	
476 Directional, 107800 Lum. Fixt. Only			$37.80
Directional Fixture Only, 107800	LS 35.3	$35.92	

	Current	Rate Per Light Per Month	
	Rate Sheet	Current	Proposed
UNDERGROUND SERVICE			
High Pressure Sodium			
412 Colonial, 4Sided, 5800L Smooth Pole			$19.74
4 Sided Colonial 5800L	LS 35	$18.76	
413 Colonial, 4Sided, 9500L Smooth Pole			$20.37
4 Sided Colonial 9500L	LS 35	$19.36	

415 Acorn, 5800L Smooth Pole			$20.13
Acorn 5800L	LS 35	$19.13	
416 Acorn, 9500L Smooth Pole			$22.48
Acorn 9500L	LS 35	$21.36	
427 London, 5800L Fluted Pole			$35.40
London(10' Fluted Pole) 5800L	LS 35.1	$33.64	
429 London, 9500L Fluted Pole			$36.21
London(10' Fluted Pole) 9500L	LS 35.1	$34.41	
431 Victorian, 5800L Fluted Pole			$33.10
Victorian(10' Fluted Pole) 5800L	LS 35.1	$31.45	
433 Victorian, 9500L Fluted Pole			$35.12
Victorian(10' Fluted Pole) 9500L	LS 35.1	$33.37	
956 Victorian/London Bases-			
Westchester/Norfolk			$ 3.61
Old Town/Manchester	LS 35.1	$ 2.83	
Chesapeake/Franklin	LS 35.1	$ 2.83	
Jefferson/Westchester	LS 35.1	$ 2.83	
Norfolk/Essex	LS 35.1	$ 3.00	
Norfolk/Essex	RLS 36.4	$ 3.81	
Jefferson/Westchester	RLS 36.1	$ 3.62	
Norfolk/Essex	RLS 36.1	$ 3.81	
423 Cobra Head, 16000L Smooth Pole			$26.23
Cobra Head, 16000L UGHPS	LS 35	$24.93	
424 Cobra Head, 28500L Smooth Pole			$28.14
Cobra Head, 28500L UGHPS	LS 35	$26.74	
425 Cobra Head, 50000L Smooth Pole			$33.50
Cobra Head, 50000L UGHPS	LS 35	$31.83	
439 Contemporary Fixt. Only 16000L			$16.18
Contemporary 16000L Fixt. Only	LS 35	$15.38	
420 Contemporary Fixt/Pole 16000L			$29.83
Contemporary 16000L	LS 35	$28.35	
440 Contemporary Fixt. Only 28500L			$17.81
Contemporary 28500L Fixt. Only	LS 35	$16.92	
421 Contemporary Fixt/Pole 28500L			$32.62
Contemporary 28500L	LS 35	$31.00	
441 Contemporary Fixt. Only 50000L			$21.59
Contemporary 50000L Fixt. Only	LS 35	$20.52	
422 Contemporary Fixt/Pole 50000L			$37.93
Contemporary 50000L	LS 35	$36.04	
400 Dark Sky, 4000 Lumen			$23.82
4000 Lum. HPS DSK Lantern	DSK 39	$22.64	
401 Dark Sky, 9500 Lumen			$24.86
9500 Lum. HPS DSK Lantern	DSK 39	$23.62	
Metal Halide			
479 Contemporary, 12000L Fixt. Only			$13.76
Contemporary Fixt. Only 12000L	LS 35.3	$13.08	
480 Contemporary, 12000L Fixt/Pole			$23.69
Contemporary Fixt./DB Pole 12000L	LS 35.3	$22.51	
481 Contemporary, 32000L Fixt. Only			$19.90
Contemporary Fixt. Only 32000L	LS 35.3	$18.91	
482 Contemporary, 32000L Fixt/Pole			$29.81
Contemporary Fixt./DB Pole 32000L	LS 35.3	$28.33	
483 Contemporary, 107800L Fixt. Only			$40.81

Contemporary Fixt. Only 107800L	LS 35.3	$38.78	
484 Contemporary, 107800L Fixt/Pole			$50.71
Contemporary Fixt./DB Pole 107800L	LS 35.3	$48.19	

Restricted Lighting Service – Rate RLS

	Current	Rate Per Light Per Month	
	Rate Sheet	Current	Proposed
OVERHEAD SERVICE			
Mercury Vapor			
252 Cobra/OpenBottom 8000L Fixt Only			$ 9.20
175W MV Outdoor Lt. after 1/1/91	RLS 36	$10.37	
175W MV Outdoor Lt.	RLS 36.3	$ 8.40	
Open Bottom 8000L MV	LS 35.2	$10.00	
175W MV Outdoor Lt.	RLS 36	$ 8.97	
175W MV Outdoor Lt. after 1/1/91	RLS 36.3	$10.19	
458 Cobra Head 8000L Fixt Only			$10.80
Cobra Head 8000L MV	LS 35.2	$10.26	
203 Cobra Head 13000L Fixt Only			$10.45
Cobra Head 13000L MV	LS 35.2	$11.74	
250W MV Outdoor Lt. after 1/1/91	RLS 36	$11.80	
250W MV Outdoor Lt.	RLS 36	$10.33	
250W MV Outdoor Lt.	RLS 36.3	$ 9.72	
250W MV Outdoor Lt. after 1/1/91	RLS 36.3	$11.61	
204 Cobra Head 25000L Fixt Only			$12.71
Cobra Head 25000L MV	LS 35.2	$15.18	
400W MV Outdoor Lt. after 1/1/91	RLS 36	$14.39	
400W MV Outdoor Lt.	RLS 36	$12.78	
400W MV Outdoor Lt.	RLS 36.3	$11.88	
400W MV Outdoor Lt. after 1/1/91	RLS 36.3	$14.19	
209 Cobra Head 60000L Fixt Only			$25.70
1000W MV Outdoor Lt. after 1/1/91	RLS 36	$26.68	
1000W MV Outdoor Lt.	RLS 36.3	$22.72	
1000W MV Outdoor Lt.	RLS 36	$24.04	
207 Directional 25000L Fixt Only			$14.78
Directional Flood 25000L MV	LS 35.2	$16.53	
400W MV Flood Lt. after 1/1/91	RLS 36	$14.39	
400W MV Flood Lt.	RLS 36	$12.78	
400W MV Flood Lt. after 1/1/91	RLS 36.3	$14.19	
400W MV Outdoor Lt. Metal Pole	RLS 36.3	$16.39	
400W MV UP	RLS 36.3	$16.39	
210 Directional 60000L Fixt Only			$26.92
1000W MV Flood Lt. after 1/1/91	RLS 36	$26.81	
1000W MV Flood Lt.	RLS 36	$24.04	
1000W MV Flood Lt.	RLS 36.3	$22.72	
1000W MV Flood Lt. after 1/1/91	RLS 36.3	$26.43	
201 Open Bottom 4000L Fixt Only			$ 7.94
100W MV Outdoor Lt.	RLS 36	$ 7.92	
100W MV Outdoor Lt.	RLS 36.3	$ 7.20	
Metal Halide			
471 Directional, 12000 L Fixt/Wood Pole			$14.79
Directional Fixt/Wood Pole, 12000	LS 35.3	$14.05	
474 Directional, 32000 L Fixt/Wood Pole			$20.42

Directional Fixt/Wood Pole, 32000	LS 35.3	$19.40	
475 Directional, 32000 L Fixt/Metal Pole			$27.99
Directional Fixt/Metal Pole, 32000	LS 35.3	$26.60	
477 Directional, 107800 L Fixt/Wood Pole			$41.03
Directional Fixt/Wood Pole, 107800	LS 35.3	$38.99	
Wood Pole (current and proposed rate on the same line)			
958 Wood Pole Installed Before 3/1/2010	LS 35.2	$10.92	$11.49
900 Wood Pole Installed Before 7/1/2004	RLS 36.1	$ 1.99	$ 2.09
	Current	Rate Per Light Per Month	
	Rate Sheet	Current	Proposed
UNDERGROUND SERVICE			
High Pressure Sodium			
275 Cobra/Cont 16000L Fixt/Smooth Pole			$24.74
150W HPS Outdoor Lt. after 1/1/91	RLS 36	$23.52	
150W UGHPS Outdoor Lt. after 1/1/91	RLS 36.3	$23.50	
150W HPS Outdoor Lt.	RLS 36	$23.52	
150W UG HPS Outdoor Lt.	RLS 36.3	$23.50	
266 Cobra/Cont 28500L Fixt/Smooth Pole			$27.03
250W UGHPS Outdoor Lt. after 1/1/91	RLS 36	$27.14	
250W HPS OLt./Metal Pole after 1/1/91	RLS 36.3	$25.20	
250W UG HPS Outdoor Lt.	RLS 36	$27.14	
250W UG HPS Outdoor Lt.	RLS 36.3	$25.20	
250W UG HPS Outdoor Lt./Metal Pole	RLS 36.3	$25.20	
250W UGHPS State of Ky Pole	RLS 36.3	$22.27	
250W UG HPS Outdoor Lt. after 1/1/91	RLS 36.3	$25.20	
267 Cobra/Cont 50000L Fixt/Smooth Pole			$30.83
400W UGHPS Outdoor Lt. after 1/1/91	RLS 36	$30.31	
400W HPS OLt./Metal Pole after 1/1/91	RLS 36.3	$27.49	
400W UG HPS Outdoor Lt.	RLS 36	$30.31	
400W UG HPS Outdoor Lt.	RLS 36.3	$27.49	
400W UG HPS Outdoor Lt./Metal Pole	RLS 36.3	$27.49	
400W UG HPS Outdoor Lt. after 1/1/91	RLS 36.3	$27.49	
276 Coach/Acorn 5800L Fixt/Smooth Pole			$14.01
70W HPS Lt. Top Mount after 1/1/91	RLS 36	$13.30	
70W HPS Lt. Top Mount after 1/1/91	RLS 36.3	$13.39	
70W HPS Lt. Top Mount	RLS 36	$13.30	
274 Coach/Acorn 9500L Fixt/Smooth Pole			$17.00
100W HPS Lt. Top Mount after 1/1/91	RLS 36	$17.68	
100W HPS Lt. Top Mount after 1/1/91	RLS 36.3	$13.99	
100W HPS Lt. Top Mount	RLS 36	$17.49	
100W HPS Lt. Top Mount	RLS 36.3	$13.99	
277 Coach/Acorn 16000L Fixture/ Smooth Pole			$21.97
150W HPS Lt. Top Mount after 1/1/91	RLS 36	$21.08	
4 Sided Colonial 16000L	LS 35	$20.36	
Acorn 16000L	LS 35	$22.27	
150W UG HPS Top Mount after 1/1/91	RLS 36.3	$20.25	
279 Contemporary 120000L Fixt. Only			$39.51
1000W HPS Outdoor Lt. after 1/1/91	RLS 36	$38.35	
1000W HPS Outdoor Lt. after 1/1/91	RLS 36.3	$33.92	

278 Contemporary 120000L Fixture/ Smooth Pole			$71.15
1000W UGHPS OL. after 1/1/91	RLS 36	$68.13	
1000W UGHPS OL. after 1/1/91	RLS 36.3	$63.70	
417 Acorn 9500L Bronze Decor Pole			$23.61
Acorn 9500L Bronze Pole	LS 35	$22.44	
419 Acorn 16000L Bronze Decor Pole			$24.50
Acorn 16000L Bronze Pole	LS 35	$23.28	
280 Victorian 5800L Fixt. Only			$19.30
70W HPS Acorn/Deco Basket	RLS 36.1	$18.45	
70W HPS Acorn/Deco Basket	RLS 36.4	$18.00	
281 Victorian 9500L Fixt. Only			$20.22
100W HPS Acorn/Deco Basket	RLS 36.1	$19.48	
100W HPS Acorn/Deco Basket	RLS 36.4	$18.91	
282 London 5800L Fixture Only			$19.46
70W HPS 8 Sided Coach	RLS 36.1	$18.63	
70W HPS 8 Sided Coach	RLS 36.4	$18.21	
283 London 9500L Fixture Only			$20.69
100W HPS 8 Sided Coach	RLS 36.1	$19.68	
100W HPS 8 Sided Coach	RLS 36.4	$19.51	
426 London, 5800L Fixt/Pole			$33.39
London(10' Smooth Pole) 5800L	LS 35.1	$31.73	
428 London, 9500L Fixt/Pole			$34.20
London(10' Smooth Pole) 9500L	LS 35.1	$32.50	
430 Victorian, 5800L Fixt/Pole			$32.41
Victorian(10' Smooth Pole) 5800L	LS 35.1	$30.80	
432 Victorian, 9500L Fixt/Pole			$34.44
Victorian(10' Smooth Pole) 9500L	LS 35.1	$32.73	
950 Victorian/London Bases, Old Town			$ 3.52
Chesapeake/ Franklin Base	LS 35.1	$ 2.83	
Old Town/Manchester	RLS 36.4	$ 3.35	
Old Town/Manchester	RLS 36.1	$ 3.35	
951 Victorian/London Bases, Chesapeake			$ 3.80
Chesapeake/ Franklin Base	RLS 36.1	$ 3.60	
Jefferson/Westchester	LS 35.1	$ 2.83	
Chesapeake/ Franklin Base	RLS 36.4	$ 3.60	
Jefferson/Westchester	RLS 36.4	$ 3.62	
901 Smooth 10' Pole			$10.99
10' Smooth Pole	RLS 36.1	$10.44	
10' Smooth Pole	RLS 36.4	$10.44	
902 Fluted 10' Pole			$13.11
10' Fluted Pole	RLS 36.1	$12.46	
10' Fluted Pole	RLS 36.4	$12.46	
Mercury Vapor			
318 Cobra Head, 8000 Lum. Fixt/Pole			$17.18
Cobra Head 8000L UGMV	LS 35.1	$21.99	
175W UG MV Metal Pole	RLS 36.3	$16.33	
175W UG MV Metal Pole after 1/1/91	RLS 36.3	$23.27	
314 Cobra Head, 13000 Lum. Fixt/Pole			$18.82
Cobra Head 13000L UGMV	LS 35.1	$23.46	
250W UG MV Outdoor Lt.	RLS 36.3	$17.69	
250W UG MV OL after 1/1/91	RLS 36.3	$24.20	
315 Cobra Head, 25000 Lum. Fixt/Pole			$22.31

Cobra Head 25000L UGMV	LS 35.1	$26.91	
400W UG MV Outdoor Lt.	RLS 36.3	$21.09	
400W UG MV OL after 1/1/91	RLS 36.3	$27.33	
400W UGMV Metal Pole after 1/1/91	RLS 36.3	$27.33	
347 Cobra Head, 25000L St. of Ky Pole			$22.30
400W UG MV State of Ky. Pole	RLS 36.3	$21.19	
206 Coach, 4000 Lum. Fixt/Pole			$12.33
4Sided Colonial 4000L UGMV	LS 35.1	$16.35	
100W MV Top Mount after 1/1/91	RLS 36	$13.15	
100W MV Top Mount	RLS 36	$13.16	
100W MV Top Mount (UG)	RLS 36.3	$11.20	
100W MV Top Mount after 1/1/91	RLS 36.3	$13.89	
208 Coach, 8000 Lum. Fixt/Pole			$13.95
4Sided Colonial 8000L UGMV	LS 35.1	$18.02	
175W MV Top Mount after 1/1/91	RLS 36	$15.03	
175W MV Top Mount	RLS 36	$14.06	
175W MV Top Mount (UG)	RLS 36.3	$12.30	
175W MV Top Mount after 1/1/91	RLS 36.3	$14.83	
Incandescent			
349 Continental Jr, 1500 Lum. Fixt/Pole			$ 8.86
100W 1500 Lum. Incand	RLS 36.4	$ 8.42	
348 Continental Jr, 6000 Lum. Fixt/Pole			$12.38
300W 6000 Lum. Incand	RLS 36.4	$11.76	

Lighting Energy Service - Rate LE

	Current	Proposed
Energy Charge per kWh:	$0.05646	$0.05942

Traffic Energy Service Rate TE

	Current	Proposed
Basic Service Charge per Month:	$3.14	$3.25
Energy Charge per kWh:	$0.06804	$0.07178

Dark Sky Friendly - Rate DSK

Current Rate

DSK Lantern	4,000	.050	$22.64
DSK Lantern	9,500	.100	$23.62

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:	$5.35	$9.42

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)

	Current	Proposed
Non-Compliance Charge:		
Primary	$16.00	$16.00
Transmission	$16.00	$16.00

Proposed Contract Option: Removes restriction that LG&E 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:		
Primary	($4.40)	($2.30)
Transmission	($4.30)	($2.25)
Non-Compliance:		
Primary	$16.00	$16.00
Transmission	$16.00	$16.00

Proposed Contract Option: Removes restriction that LG&E 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

Customer shall pay for excess facilities by:

Monthly Charge for Leased Facilities:	1.66%
Monthly Charge for Facilities Supported By a One-Time CIAC Payment:	0.86%

Proposed

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 1.37%

(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 0.55%

Standard Rider for Redundant Capacity Charge – Rider RC

	Current (Per kW)	Proposed (Per kW/kVA)
Capacity Reservation Charge per Month:		

Secondary Distribution	$1.52	$1.13
Primary Distribution	$1.13	$0.88

Standard Rider for Supplemental or Standby Service – Rider SS

	Current (Per kW)	Proposed (Per kW/kVA)
Contract Demand per month:		
Secondary	$8.23	$13.14
Primary	$7.21	$12.50
Transmission	$6.08	$11.28

Availability of Service: Text addition clarifies that LG&E 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 LG&E 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	$0.05046	$0.05235
Intermediate Hours	$0.07070	$0.07335
Peak Hours	$0.13448	$0.13951

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

Disconnect/Reconnect Service Charge

Current Rate: $29.00
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

Current Rate

For Customers Served Under Residential Service Rate RS $135.00

(For Combination Electric and Gas Residential Customers the total deposit would be $250.00)

For Customers Served Under General Service Rate GS $220.00

For all other Customers not classified herein, the deposit will be no more than 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly.

Company may offer 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.

Proposed Rate

For Customers Served Under Residential Service Rate RS $135.00

(For Combination Electric and Gas Residential Customers the total deposit would be $230.00)

For Customers Served Under General Service Rate GS $220.00

For all other Customers not classified herein, the deposit will be no more than 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly.

Company may offer 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. Text change states when Rate GS deposit may be waived in conjunction with taking service under Rate RS.

LG&E CURRENT AND PROPOSED GAS RATES

Residential Gas Service - Rate RGS

	Current	Proposed
Basic Service Charge per delivery point per month:	$12.50	$15.50
Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.22396	$ 0.23121
Gas Supply Cost Component	0.34904	0.34904
Total Charge Per 100 Cubic Feet	$ 0.57300	$ 0.58025

Volunteer Fire Department Service – Rate VFD

	Current	Proposed
Basic Service Charge per delivery point per month:	$12.50	$15.50
Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.22396	$ 0.23121
Gas Supply Cost Component	0.34904	0.34904
Total Charge Per 100 Cubic Feet	$ 0.57300	$ 0.58025

Firm Commercial Gas Service - Rate CGS

	Current	Proposed

Basic Service Charge per delivery point per month if all of the customer's meters have a capacity < 5000 cf/hr:	$ 30.00	$ 35.00
Basic Service Charge per delivery point per month if all of the customer's meters have a capacity > 5000 cf/hr:	$170.00	$175.00
Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.18722	$ 0.21142
Gas Supply Cost Component	0.34904	0.34904
Total Charge Per 100 Cubic Feet	$ 0.53626	$ 0.56046

Firm Industrial Gas Service - Rate IGS

	Current	**Proposed**
Basic Service Charge per delivery point per month if all of the customer's meters have a capacity < 5000 cf/hr:	$ 30.00	$ 35.00
Basic Service Charge per delivery point per month if all of the customer's meters have a capacity > 5000 cf/hr:	$170.00	$175.00
Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.19022	$ 0.21523
Gas Supply Cost Component	0.34904	0.34904
Total Charge Per 100 Cubic Feet	$ 0.53926	$ 0.56427

As-Available Gas Service – Rate AAGS

	Current	**Proposed**
Basic Service Charge per delivery point per month:	$275.00	$275.00
Charge Per Mcf:		
Distribution Cost Component	$ 0.5252	$ 0.6117
Gas Supply Cost Component	3.4904	3.4904
Total Charge Per 100 Cubic Feet	$ 4.0156	$ 4.1021

Firm Transportation Service (Transportation Only) Rate FT

	Current	**Proposed**
Administration Charge per delivery delivery point per month:	$230.00	$600.00
Distribution Charge Per Mcf	$ 0.43	$ 0.43
Utilization Charges for Daily Imbalances:		
Daily Demand Charge	$ 0.1722	$ 0.1722
Daily Storage Charge	0.1833	0.1833
Utilization Charge Per Mcf	$ 0.3555	$ 0.3555

Plus: Any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas.

Proposed Gas Cost True-Up Charge: (No current provision) The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rate FT. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rate FT in order to recover from (or refund to) transferring sales customers any under- or over-collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly GSC filings.

For customers electing service under Rate FT effective November 1, 2010, the Gas Cost True-Up Charge shall be:

($0.1593) per Mcf for Bills Rendered On and After May 1, 2012

For customers electing service under Rate FT effective November 1, 2011, the Gas Cost True-Up Charge shall be:

($0.1709) per Mcf for Bills Rendered On and After May 1, 2012

Proposed Minimum Daily Threshold Requirement and Charge: (No current provision) When Customer's daily usage falls below the Minimum Daily Threshold Requirement, Customer will be charged a Minimum Daily Threshold Charge equal to the difference between the Minimum Daily Threshold Requirement and the Customer's actual consumption in Mcf for that day multiplied by the Distribution Charge hereunder. The Minimum Daily Threshold Requirement is equal to the minimum daily volume of 50 Mcf. Such Minimum Daily Threshold Charge shall be accumulated for each day of the applicable month and billed during that month in accordance with the following formula:

Minimum Daily Threshold Charge =

(Minimum Daily Threshold minus Customer Usage on Given Day) times the Distribution Charge

Such daily amount shall be accumulated for each day of the month and the total will be applied to Customer's bill.

In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by the Pipeline Transporter, then the Company proposes to require Customer to pay such penalties, fees or charges as determined by Company and in accordance with the payment provisions of the applicable rate schedule in addition to any and all other charges due thereunder.

The imbalance threshold for the imposition of the Utilization Charge for Daily Imbalances is proposed to be reduced from +/- 10% of the delivered volume of gas on any day when an Operational Flow Order is not in effect to +/- 5% of such volumes.

Distribution Generation Gas Service - Rate DGGS

	Current	Proposed
Basic Service Charge per delivery point per month if all of the customer's meters		

have a capacity < 5000 cf/hr:	$ 30.00	$ 35.00
Basic Service Charge per delivery point per month if all of the customer's meters have a capacity > 5000 cf/hr:	$170.00	$175.00
Demand Charge Per 100 Cubic Feet	$ 1.0110	$ 1.0900
Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.02744	$ 0.03222
Gas Supply Cost Component	0.34904	0.34904
Total Charge Per 100 Cubic Feet	$ 0.37648	$ 0.38126

The minimum Monthly Billing Demand, which is currently ten (10) Ccf, is proposed to be increased to four hundred and eighty (480) Ccf.

Gas Transportation Service/Standby - Rider TS

Current Rate

Administration Charge: $153.00 per Delivery Point per month.

	CGS	IGS	AAGS
Distribution Charge Per Mcf	$1.8722	$1.9022	$0.5252
Pipeline Supplier's Demand Component	0.8800	0.8800	0.8800
Total	$2.7522	$2.7822	$1.4052

Plus: Any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas.

Proposed Rate

Gas Transportation Service/Standby
Rider TS would cease to be available October 31, 2013

Administrative Charge: $592.00 per Delivery Point per month.

	CGS	IGS	AAGS
Distribution Charge Per Mcf	$2.1142	$2.1523	$0.6117
Pipeline Supplier's Demand Component	0.8800	0.8800	0.8800
Total	$2.9942	$3.0323	$1.4917

Plus: Any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas.

PROPOSED NEW RIDER TS-2
Gas Transportation Service/Firm Balancing Service Rider
Proposed Rider TS-2 would become available November, 1, 2013

Administrative Charge: $600.00 per Delivery Point per month.
Monthly Telemetry Charge Per Delivery Point Per Month: $300.00

	CGS	IGS	AAGS
Distribution Charge Per Mcf	$2.1142	$2.1523	$0.6117
Pipeline Supplier's Demand Component	0.8800	0.8800	0.8800
Total	$2.9942	$3.0323	$0.4917

Plus: Any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas.

Proposed Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder and not previously served under Rider TS. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rider TS-2. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rider TS-2 in order to recover from (or refund to) transferring sales customers any under- or over-collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly GSC filings.

For customers electing service under Rate TS-2 effective November 1, 2010, the Gas Cost True-Up Charge shall be:

($0.1593) per Mcf for Bills Rendered On and After May 1, 2012

For customers electing service under Rate TS-2 effective November 1, 2011, the Gas Cost True-Up Charge shall be:

($0.1709) per Mcf for Bills Rendered On and After May 1, 2012

Proposed Minimum Annual Threshold Requirement and Charge: When Customer's annual usage falls below the Minimum Annual Threshold Requirement, Customer will be charged a Minimum Annual Threshold Charge equal to the difference between the Minimum Annual Threshold Requirement of 25,000 Mcf and the Customer's actual consumption in Mcf during each Contract Year which difference shall be multiplied by the peak period Distribution Charge of the applicable sales rate schedule. Such Minimum Annual Threshold Charge shall be billed during the month following the close of the Contract Year in accordance with the following formula

Minimum Annual Threshold Charge =

(Minimum Annual Threshold minus Customer's Annual Usage) times the Peak Period Distribution Charge

Such amount shall be applied to Customer's November bill.

Payment of the Minimum Annual Threshold Charge is not a remedy for Customer's failure to meet the Minimum Annual Threshold Requirement for service under Rider TS-2. In the event that Customer does not meet the Minimum Annual Threshold Requirement for two (2) consecutive years (as determined for the 12 months ended October), service to Customer under this rider may be discontinued. Customer and its TS-2 Pool Manager will receive notice by December 1 that Customer will be removed from the TS-2 Pool and returned to firm sales service effective April 1 of the following year.

New customers qualifying for service hereunder and who begin service prior to the November 1 date specified above shall not be subject to any Minimum Annual Threshold Charge for service prior to the November 1 date immediately following the commencement of service hereunder.

Gas Meter Pulse Service Rider GMPS

Current

Monthly Charge:

For Customers Served Under Rate Schedule FT: $ 8.10

For Customers Not Served Under Rate Schedule FT: $21.06

Proposed

Monthly Charge:

For Customers Served Under Rate Schedule FT and Rider TS-2: $ 7.25

For Customers Not Served Under Rate Schedule FT and Rider TS-2: $24.60

Pooling Service Rider to Rider TS - Rider PS-TS

Rider PS-TS would cease to be available October 31, 2013

Current

In addition to any charges billed directly to TS Pool Manager or Customer as a result of the application of Rider TS or this rider, the following PS-TS Pool Administration Charge shall apply per Customer per month: $75.00

Proposed

In addition to any charges billed directly to TS Pool Manager or Customer as a result of the application of Rider TS or this rider, the following PS-TS Pool Administrative Charge shall apply per Customer per month: $75.00

PROPOSED NEW RIDER PS-TS-2

Pooling Service Rider to Rider TS-2

Proposed Rider PS-TS-2 would become available November 1, 2013

In addition to any charges billed directly to TS-2 Pool Manager or Customer as a result of the application of Rider TS-2 or this rider, the following PS-TS-2 Pool Administrative Charge shall apply per Customer per month: $75.00

In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by the Pipeline Transporter, then the Company proposes to require Customer to pay such penalties, fees or charges as determined by Company and in accordance with the payment provisions of the applicable rate schedule in addition to any and all other charges due thereunder.

Action Alert Charge

Company shall have the right to issue an Action Alert ("AA") which will require actions by the TS-2 Pool Manager to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. Upon issuance of an AA, Company will direct TS-2 Pool Manager to deliver to Company from 0% to 100% of the total MDQ of those Customers in the TS-2 Pool (the PMDQ as defined hereafter). Any volume delivered by TS-2 Pool Manager that differs (either more or less) from the volume specified in the AA shall be subject to an Action Alert Charge. The Action Alert Charge shall be equal to $5.00 plus the mid-point price posted in *Platts Gas Daily* for Dominion South Point per Mcf on the day for which the AA was violated, plus any other charges under this rider.

The Company proposes a cash-out provision for delivery imbalances that is the same as the provision in the current Rider TS. Under that provision, over-deliveries by the Pool Manager are purchased by the Company and under-deliveries are sold to the Pool Manager. The sales and purchases are made at formula rates based on percentages of the *Platts Gas Daily* price for Dominion South Point, depending on the level of over- or under-deliveries during the month.

The Company proposes a provision for Lost and Unaccounted For Gas ("LAUFG") that requires the Pool Manager to gross up the volume scheduled for delivery to the Company for its pool to cover lost and unaccounted for gas. The proposed LAUFG factor is a rolling 3-year weighted average of LAUFG associated with sales volumes and transportation volumes pursuant to Rider TS and Rider TS-2.

Pooling Service Rider to Rate FT - Rider PS-FT

In addition to any charges billed directly to FT Pool Manager or Customer as a result of the application of Rate FT or this rider, the following charge shall apply per customer in FT Pool per month:

	Current	**Proposed**
PS-FT Pool Administration Charge:	$75	$75

In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by the Pipeline Transporter, then the Company proposes to require Customer to pay such penalties, fees or charges as determined by Company and in accordance with the payment provisions of the applicable rate schedule in addition to any and all other charges due thereunder.

The imbalance threshold for the imposition of the Utilization Charge for Daily Imbalances is proposed to be reduced from +/- 5% of the delivered volume of gas on any day when an Operational Flow Order is not in effect to +/- 2% of such volumes.

Excess Facilities – Rider EF

Current

Customer shall pay for excess facilities by:

Monthly Charge for Leased Facilities:	1.66%
Monthly Charge for Facilities Supported By a One-Time CIAC Payment:	0.86%

Proposed

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	1.29%

(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	0.48%

Gas Supply Clause

The Company proposes to recover the net uncollectible gas cost portion of bad debt expense through the Actual Adjustment component of the Gas

Supply Clause.

The Company proposes to provide for the ability to reflect reductions in gas cost through the Gas Supply Clause upon twenty (20) days' notice. Increases in gas cost would continue to be reflected on a quarterly basis.

The Company proposes to include in the Gas Cost Balance Adjustment and the Gas Cost Actual Adjustment of the Gas Supply Clause carrying charges on any over- and under-recoveries of gas cost at the Company's weighted average cost of capital.

Gas Line Program

LG&E is also requesting a Certificate of Public Convenience and Necessity from the Kentucky Public Service Commission for its proposed Gas Line Program (the "Program"). Currently, gas service lines and risers are owned by LG&E customers. As part of the Program, LG&E is seeking to undertake a five-year program to proactively replace certain gas risers, and is also requesting the Commission to approve LG&E taking ownership of gas service lines and risers pursuant to 807 KAR 5:022, Section 9(17)(a)(2) as LG&E repairs, replaces or installs gas service lines and risers.

In connection with the Program, LG&E is also proposing a Gas Line Tracker. The Gas Line Tracker is a rate mechanism that is designed to recover the cost of the five-year Program, including a reasonable return on construction and other capital expenditures and reasonable operating expenses depreciation expense and related taxes. The proposed Gas Line Tracker will also recover the costs of LG&E's gas leak mitigation program, which includes its existing gas main replacement program, including reasonable return on construction and other capital expenditures and reasonable operating expenses. This tracker will function like the similar rider in place and approved for another gas distribution company in Kentucky.

Under the proposed Program, if approved, LG&E will replace gas service risers of a type that have been reported to be at risk of leaks or failures, and will take on the obligation to repair, replace and install gas service lines going forward. The Program will be implemented throughout LG&E's gas service territory. The manner in which the Program will be implemented is described in greater detail in LG&E's application. LG&E is proposing several changes to its gas Terms and Conditions to address LG&E's ownership and future service of customers' gas risers and service lines, as well as property access and easement matters related to the same.

The Program will not compete with any other utility, but implementation of the Program may compete with plumbers, contractors, and others in the construction industry who could potentially install, repair or replace gas service lines and risers.

The total estimated capital cost of the program over the five-year period for which the Company is seeking recovery at this time is $256 million. Additional operation and maintenance expenses will be incurred for this project. The Company estimates these O&M costs at approximately $11 million, for which the Company is also seeking recovery at this time.

PROPOSED NEW ADJUSTMENT CLAUSE GLT
Gas Line Tracker Cost Recovery Mechanism

Applicability: Applicable to all customers receiving service under the Company's Rate Schedules RGS, VFD, CGS, IGS, AAGS, and DGGS.

Calculation of the Gas Line Tracker Revenue Requirement:

The GLT Revenue Requirement includes the following:

a. GLT Rider-related Plant In-Service not included in base gas rates minus the associated GLT related accumulated depreciation and accumulated deferred income taxes;
b. Retirement and removal of plant related to GLT construction;
c. The rate of return on the net rate base is the overall rate of return on capital authorized in the Company's latest base gas rate case, grossed up for federal and state income taxes;
d. Depreciation expense on the GLT-related Plant In-Service less retirement and removals; and
e. Incremental Operation and Maintenance

GLT Program Factors

All customers receiving service under rate schedules RGS, VFD, CGS, IGS, AAGS, and DGGS shall be assessed an adjustment to their applicable rate schedule that will enable the Company to recover the costs associated with the GLT program. After the Company replaces a gas service riser or a gas service line under this program, it will assume ownership and responsibility for the plant and equipment. The allocation of the program cost to customers will be in proportion to their relative base revenue share approved in Case No. 2012-00222.

A filing to update the projected program costs will be submitted annually at least two (2) months prior to the beginning of the effective period. The filing will reflect the anticipated impact on the Company's revenue requirements of net plant additions expected during the upcoming year. After the completion of a plan year, the Company will submit a balancing adjustment to true up the actual costs with the projected program costs for the preceding year. Such adjustment to the GLT will become effective with the first billing cycle on or after the effective date of such change.

The charges for the respective gas service schedules for the first billing cycle of January 2013 are:

RGS-Residential Gas Service	$ 2.35
VFD-Volunteer Fire Department Service	$ 2.35
CGS-Commercial Gas Service	$ 11.60
IGS-Industrial Gas Service	$ 93.25
AAGS-As Available Gas Service	$514.23
DGGS – Distributed Generation Gas Service	$ 0

Meter Test Charge

Current Rate	$80.00
Proposed Rate	$90.00

Disconnect/Reconnect Service Charge

Current Rate	$29.00
Proposed Rate	$28.00

Inspection Charge

Current Rate	$135.00
Proposed Rate	$150.00

Additional Trip Charge
Applicable to Rate FT, Rider TS-2, and Rider GMPS

Current Rate	$150.00 (Currently a Provision in Rider GMPS only)
Proposed Rate	$150.00 (Applicable to Rate FT, Rider TS-2, and Rider GMPS)

Customer Deposits

Current Rate

For Customers Served Under
Residential Gas Service Rate RGS $115.00
(For Combination Gas and Electric Residential Customers,
the total deposit would be $250.00)

For Non-Residential Gas Customers, the deposit will be no more than 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly. Company may offer 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.

Proposed Rate

For Customers Served Under
Residential Gas Service Rate RGS $ 95.00
(For Combination Gas and Electric Residential Customers,
the total deposit would be $230.00)

For Non-Residential Gas Customers, the deposit will be no more than 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly. Company may offer 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.

Louisville Gas and Electric Company proposes to change the text of the following electric tariffs: General Service Rate GS, Power Service Rate PS, Industrial Time-of-Day Secondary Service Rate ITODS, Commercial Time-of-Day Secondary Service Rate CTODS, Industrial Time-of-Day Primary Service Rate ITODP, Commercial Time-of-Day Primary Service Rate CTODP, Retail Transmission Service Rate RTS, Fluctuating Load Service Rate FLS, Lighting Service Rate LS, Restricted Lighting Service Rate RLS, Cable Television Attachment Charges Rate CTAC, Curtailable Service Rider CSR10, Curtailable Service Rider CSR30, Small Capacity Cogeneration and Small Power Production Qualifying Facilities Rider SQF, Excess Facilities Rider EF, Redundant Capacity Rider RC, Supplemental/Standby Service Rider SS, Rider IL for Intermittent Loads, Temporary/Seasonal Service Rider TS, Kilowatt-Hours Consumed By Street Lighting Units, Large Green Energy

Rider LGE, Economic Development Rider EDR, 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 in 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 LG&E 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.

Louisville Gas and Electric Company proposes to change the text of the following gas tariffs: Residential Gas Service Rate RGS, Volunteer Fire Department Rate VFD, Firm Commercial Gas Service Rate CGS, Firm Industrial Gas Service Rate IGS, As-Available Gas Service Rate AAGS, Firm Transportation Service Rate FT, Distributed Generation Gas Service Rate DGGS, Special Charges, Gas Transportation Service/Standby Rider TS, Gas Meter Pulse Service Rider GMPS, Pooling Service Rider PS-TS, Pooling Service Rate PS-FT, Excess Facilities EF, Gas Supply Clause GSC, Demand Side Management Cost Recovery Mechanism DSM, Experimental Performance Based Rate Mechanism PBR, and the Terms and Conditions.

Complete copies of the proposed tariffs containing the text changes and proposed rates may be obtained by contacting Lonnie E. Bellar, Louisville Gas and Electric Company at P. O. Box 32010, Louisville, Kentucky, 502-627-4830, or by visiting Louisville Gas and Electric Company’s website at www.lge-ku.com.

The foregoing rates reflect a proposed annual increase in electric revenues of approximately 6.9% and gas revenues of approximately 7.0% to Louisville Gas and Electric 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	$30,238,063	8.60%	$ 7.25	8.60%
General Service	$6,743,615	5.09%	$ 12.98	5.09%
Power Service	$8,781,864	4.59%	$ 244.40	4.59%
TOD Power - Sec	$2,631,417	6.52%	$ 1,351.52	6.52%
TOD Power - Pri	$8,107,174	7.20%	$ 7,336.81	7.20%
Retail Transmission	$2,243,796	7.54%	$16,780.65	7.54%
Outdoor Lights	$ 871,225	5.01%	$ 0.76	5.01%
Lighting Energy	$ 11,397	5.01%	$ 5.57	5.01%
Traffic Energy	$ 13,007	5.01%	$ 1.06	5.01%

CTAC	$ 353,101	76.07%	N/A	N/A

The estimated amount of the annual change and the average monthly bill to which the proposed gas rates will apply for each gas customer class is as follows:

Gas Rate Class	Annual $ Increase	Annual % Increase	Mthly Bill $ Increase	Mthly Bill % Increase
Residential	$11,950,450	7.57%	$ 3.42	7.57%
Commercial	$ 4,186,992	6.07%	$ 13.57	6.07%
Industrial	$ 237,585	5.09%	$ 90.99	5.09%
As-Available	$ 31,551	2.10%	$207.57	2.10%
Firm Transportation	$ 333,011	6.45%	$370.01	6.45%
Distributed Generation	$ 0	0.00%	$ 0	0.00%

The estimated impact of the proposed Gas Line Tracker on each applicable rate schedule is as follows:

Year/ Effect	Rates RGS/VFD	Rate CGS	Rate IGS	Rate AAGS	Rate DGGS
2013					
$ Increase	$2.35	$11.60	$93.25	$514.23	$0.00
% Increase	5.19%	5.19%	5.22%	5.19%	0.0%
2014					
$ Increase	$3.35	$16.55	$132.98	$733.35	$0.00
% Increase	7.40%	7.40%	7.44%	7.40%	0.0%
2015					
$ Increase	$4.69	$23.19	$186.34	$1,027.58	$0.00
% Increase	10.37%	10.37%	10.42%	10.37%	0.0%
2016					
$ Increase	$6.08	$30.07	$241.63	$1,332.51	$0.00
% Increase	13.45%	13.45%	13.51%	13.45%	0.0%
2017					
$ Increase	$6.76	$33.43	$268.64	$1,481.43	$0.00
% Increase	14.96%	14.96%	15.02%	14.96%	0.0%

LG&E is proposing no change to the required Customer Deposit for residential electric customers served under Residential Rate RS. It will remain $135.00 (0% increase). LG&E proposes to decrease the required Customer Deposit for residential gas customers served under Residential Gas Service Rate RGS from the current amount of $115.00 to $95.00 (17% decrease). The Customer Deposit for combined gas and electric residential service, if required, would decrease from the current amount of $250.00 to $230.00 (8% decrease). LG&E does not propose to change the Customer Deposit amount required for non-residential electric customers served under General Service Rate GS, which is currently $220.00 (0% increase). Text change states when Rate GS deposit may be waived in conjunction with taking service under Rate RS.

The rates contained in this notice are the rates proposed by Louisville Gas and

Electric 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 filings made by the utility by contacting Lonnie E. Bellar, Vice President – State Regulation and Rates, Louisville Gas and Electric Company, 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 Louisville Gas and Electric Company, 701 South Ninth Street, Louisville, Kentucky, or the Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky.

A copy of this Notice and the proposed electric and gas tariffs, once filed, shall also be available for public inspection on Louisville Gas and Electric Company's website at www.lge-ku.com.

<table>
<tr><td>Louisville Gas and Electric Company
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40232
502-627-4830</td><td>Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40601
502-564-3940</td></tr>
</table>

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 Louisville Gas and Electric Notice.

Bardstown KY Standard
Bedford Trimble Banner
Brandenburg Meade Co. Messenger
Cave City Barren Co. Progress
Edmonton Herald News
Elizabethtown Hardin Co. Independent
Elizabethtown News Enterprise
Glasgow Daily Times
Greensburg Record Herald
Hodgenville Larue Co. Herald
Lagrange Oldham Era
Lebanon Enterprise
Louisville Courier Journal
Munfordville Hart Co. Herald
New Castle Henry Co. Local
Shelbyville Sentinel News
Shepherdsville Pioneer News
Springfield Sun
Taylorsville Spencer Magnet

Louisville Gas and Electric Company
Case No. 2012-00222
Historical Test Period Filing Requirements

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

<u>Description of Filing Requirement:</u>

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.

<u>Response:</u>

See attached.

a PPL company

Louisville Gas and
Electric 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 Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, a Certificate of Public Convenience and Necessity, Approval of Ownership of Gas Service Lines and Risers, and a Gas Line Surcharge*** **– Case No. 2012-00_______**

Dear Mr. DeRouen:

Please take notice that Louisville Gas and Electric Company ("LG&E") intends to file on or after June 29, 2012, a rate application for a general adjustment in its electric and gas rates, including changes to its electric and gas tariffs. The application will be supported by a historic test year ending March 31, 2012. LG&E will also be seeking a Certificate of Public Convenience and Necessity and Commission permission to take ownership of customers' gas service lines and risers. The application will seek approval for a new surcharge mechanism to recover the costs associated with the ownership of customers' gas service lines and risers, and other LG&E infrastructure replacements.

LG&E 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].

Louisville Gas and Electric Company
Case No. 2012-00222
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 LG&E's Application.

Louisville Gas and Electric Company
Case No. 2012-00222
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 LG&E's Application.

Louisville Gas and Electric Company
Case No. 2012-00222
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:

LG&E 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].

Louisville Gas and Electric Company
Case No. 2012-00222
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:

LG&E 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 LG&E filed its application.

Louisville Gas and Electric Company
Case No. 2012-00222
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 LG&E's Application.

Louisville Gas and Electric Company
Case No. 2012-00222
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:

LG&E 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].

Louisville Gas and Electric Company
Case No. 2012-00222
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.

Louisville Gas and Electric Company
Case No. 2012-00222
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:

LG&E will comply with 807 KAR 5:001, Section 10(5) by publishing the Notice of Hearing in the newspapers in the areas affected. LG&E's advertisement of the Notice of Hearing shall comply with KRS 424.300.

Louisville Gas and Electric Company
Case No. 2012-00222
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, John Clay Murphy, and Robert M. Conroy.

Louisville Gas and Electric Company
Case No. 2012-00222
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
- John Clay Murphy
- Robert M. Conroy

Louisville Gas and Electric Company
Case No. 2012-00222
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 LG&E's Application.

Louisville Gas and Electric Company
Case No. 2012-00222
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 LG&E's annual electric revenues approximately $62,057,882 or 6.9%, and will increase LG&E's annual gas revenues approximately $17,200,997 or 7.0%.

Louisville Gas and Electric Company
Case No. 2012-00222
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:

Louisville Gas and Electric Company - Electric				
Electric Rate Class	Annual $ Increase	Annual % Increase	Mthly Bill $ Increase	Mthly Bill % Increase
Residential	$30,238,063	8.60%	$ 7.25	8.60%
General Service	$6,743,615	5.09%	$ 12.98	5.09%
Power Service	$8,781,864	4.59%	$ 244.40	4.59%
TOD Power - Sec	$2,631,417	6.52%	$ 1,351.52	6.52%
TOD Power - Pri	$8,107,174	7.20%	$ 7,336.81	7.20%
Retail Transmission	$2,243,796	7.54%	$16,780.65	7.54%
Outdoor Lights	$ 871,225	5.01%	$ 0.76	5.01%
Lighting Energy	$ 11,397	5.01%	$ 5.57	5.01%
Traffic Energy	$ 13,007	5.01%	$ 1.06	5.01%
CTAC	$ 353,101	76.07%	N/A	N/A

Louisville Gas and Electric Company - Gas				
Gas Rate Class	Annual $ Increase	Annual % Increase	Mthly Bill $ Increase	Mthly Bill % Increase
Residential	$11,950,450	7.57%	$ 3.42	7.57%
Commercial	$ 4,186,992	6.07%	$ 13.57	6.07%
Industrial	$ 237,585	5.09%	$ 90.99	5.09%
As-Available	$ 31,551	2.10%	$207.57	2.10%
Firm Transportation	$ 333,011	6.45%	$370.01	6.45%
Distributed Generation	$ 0	0.00%	$ 0	0.00%

Louisville Gas and Electric Company
Case No. 2012-00222
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 LG&E's Application.

Louisville Gas and Electric Company
Case No. 2012-00222
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.

Louisville Gas and Electric Company
Case No. 2012-00222
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.

Louisville Gas and Electric Company
Revenue Requirement as of March 31, 2012

		Electric	Gas	
1	Fuel	322,585,675	-	(1)
2	Purchased Power	69,067,179	-	(2)
3	Purchased Gas	-	744,963	(3)
4	Operations and Maintenance	281,892,125	59,570,814	(4)
5	Depreciation and Amortization Expense	128,520,420	25,091,373	(5)
6	Regulatory Credits	(3,858,163)	(2,104,902)	(6)
7	Taxes Other Than Income Taxes	22,116,266	6,625,320	(7)
8	Net Operating Income Found Reasonable	154,920,631	40,852,576	(8)
9	Income Tax	68,439,800	19,680,128	(9)
10	Gains from Disposition of Allowances	(694)	-	(10)
11	Accretion Expense	1,651,510	1,059,702	(11)
12	Total Cost of Service (Revenue Requirement)	1,045,334,749	151,519,974	
13	Revenues at Present Rates	983,266,246	134,318,108	(12)
14	Revenue Deficiency	62,068,503	17,201,866	(13)

(1) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] electric income statement, line 11
(2) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] electric income statement, line 12
(3) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] gas income statement, line 12
(4) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] electric income statement, line 13 and gas income statement, line 13
(5) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] electric income statement, line 14 and gas income statement, line 14
(6) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] electric income statement, line 15 and gas income statement, line 15
(7) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] electric income statement, line 16 and gas income statement, line 16
(8) See Blake Exhibit 8, line 3
(9) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] electric income statement, line 17 ($45,044,292) and Blake Exhibit 8, line 7 - line 5 ($23,395,508); See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] gas income statement, line 17 ($13,196,221) and Rives Exhibit 8, line 7 - line 5 ($6,483,907)
(10) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] electric income statement, line 18
(11) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] electric income statement, line 19
(12) See Filing Requirement pursuant to 807 KAR Section 10(7)(a) [Tab 42] electric income statement, line 8 and gas income statement, line 9
(13) See Blake Exhibit 8, line 7

Louisville Gas and Electric Company
Case No. 2012-00222
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.

LOUISVILLE GAS AND ELECTRIC COMPANY

Reconciliation of Capitalization and Net Original Cost Rate Base

Line No.		Total Company Balance as of 3/31/2012	Electric	Gas
1	Rate Base Percentage (Exhibit 3, Line 19)		79.01%	20.99%
2	Capitalization:			
3	Common Equity	$ 1,387,034,687		
4	Long-Term Debt	1,105,705,507		
5	Subtotal	$ 2,492,740,194	$ 1,969,514,027	$ 523,226,167
6	Adjustments to Capitalization:			
7	Trimble County Inventories	(4,178,761)	(4,178,761)	-
8	Investments in OVEC and Other	(606,165)	(606,165)	-
9	JDIC	19,072,275	18,547,474	524,801
10	Advanced Coal Investment Tax Credit	22,976,500	22,976,500	-
11	Environmental Compliance Programs	(20,091,143)	(20,091,143)	-
12	Subtotal	17,172,706	16,647,905	524,801
13				
14	Total Capitalization As Filed	$ 2,509,912,900	$ 1,986,161,932	$ 523,750,968
15				
16	Assets per books not included in rate base:			
17	Net ARO Assets	(47,329,492)	(27,021,378)	(20,308,114)
18	Other Property & Investments	(26,812,548)	(21,057,360)	(5,755,188)
19	Misc. Current Assets	(695)	(549)	(146)
20	Unamortized Debt Expense	(12,916,551)	(10,205,367)	(2,711,184)
21	Unamortized Loss on Bonds	(20,682,090)	(16,340,919)	(4,341,171)
22	Deferred Regulatory Assets	(388,800,142)	(307,190,992)	(81,609,150)
23	Other Deferred Debits	(1,804,929)	(1,426,074)	(378,855)
24	BTL Portion of Accumulated Deferred Income Taxes	205,095	162,888	42,207
25	Subtotal	(498,141,352)	(383,079,751)	(115,061,601)
26				
27	Liabilities per books not included in rate base:			
28	Other Deferred Credits	8,148,017	6,437,748	1,710,269
29	Regulatory Liabilities	25,098,349	18,497,185	6,601,164
30	ARO Liabilities	59,331,864	46,878,106	12,453,758
31	Misc. Long-term Liabilities	53,954,917	42,629,780	11,325,137
32	Accumulated Provision for Pension & Postretirement	160,669,174	126,944,714	33,724,460
33	Subtotal	307,202,321	241,387,533	65,814,788
34				
35	Items included in rate base:			
36	Inventory - 13 month average vs. end of period	7,844,618	(2,513,767)	10,358,385
37	Prepayments - 13 month average vs. end of period	236,905	554,001	(317,096)
38	Environmental Compliance Programs	20,091,143	20,091,143	-
39	Cash Working Capital Formula vs. Actual	84,198,628	77,386,580	6,812,048
40	Capitalization / Rate Base Allocation Differences	-	(18,990,003)	18,990,003
41	Subtotal	112,371,294	76,527,954	35,843,340
42				
43	Total Reconciliation	(78,567,737)	(65,164,264)	(13,403,473)
44				
45	Total Net Original Cost Rate Base (Exhibit 3, Line 18)	$ 2,431,345,163	$ 1,920,997,668	$ 510,347,495

Louisville Gas and Electric Company
Case No. 2012-00222
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%
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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
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427188	INT EXP-PCB CC2002C $96M 10/32
427189	INT EXP-PCB TC2002A $41.665M 10/32

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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-EI-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

Louisville Gas and Electric Company
Case No. 2012-00222
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:

LG&E has not received any written communication from its auditor that there are any material weaknesses in LG&E's internal controls.

See attached.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Sole Stockholder of Louisville Gas and Electric Company

We have audited the accompanying balance sheet of Louisville Gas and Electric 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 Louisville Gas and Electric 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

Louisville Gas and Electric Company
Case No. 2012-00222
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 LG&E'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 LG&E 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 FERC has not conducted an audit of LG&E's natural gas business, and, therefore, no such audit reports exist. The Federal Communications Commission has not conducted an audit of LG&E, 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 J. 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**

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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.

Code of Conduct Compliance

- *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.

<u>Actions Already Taken by LG&E</u>

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

[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.

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[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

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[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

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[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.

<u>Pertinent Guidance</u>

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

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[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

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[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 (4th) 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

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[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 <u>not</u> 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. <u>Password Access to EMS Information</u>.

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. Disclosure of Transmission and Customer Information.

a. Disclosure of Transmission Information by Telephone.

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: http://www.eon-us.com/regulatory/disclosure_of_information.pdf.

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 all 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 all 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.

[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

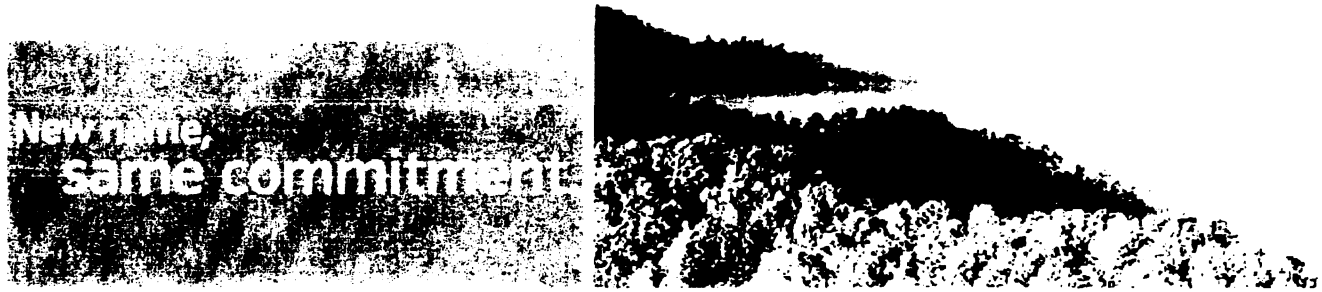
cc: Carl Coscia
Lyle Hanagami
Eliot Wessler
FERC, Office of Enforcement, Division of Audits

Steven D. Phillips
E.ON U.S. LLC

R. Michael Sweeney, Jr.
Hunton & Williams LLP

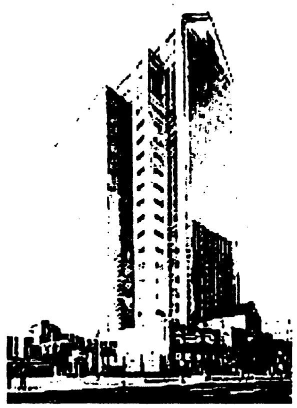
ATTACHMENT A

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)

Terms of Use Contractor Health and Safety Site Wellness Site

Louisville Gas and Electric Company
Case No. 2012-00222
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:

LG&E's most recent FERC Form 1 and KPSC Annual Report for Major Natural Gas Companies for the year ended December 31, 2011, are attached**.** Please note that by a FERC Order dated July 12, 2007 in FERC Docket No. CP07-232-000, LG&E was granted a Section (7) exemption by the FERC under the Natural Gas Act, and as a part of that exemption LG&E was granted "a waiver of reporting and accounting requirements," which includes the filing of Form 2 with the FERC. In addition, on February 15, 2008, the Public Service Commission issued an order granting LG&E's request to cease the annual filing of the FERC Form 2.[1] In lieu of filing a FERC Form 2 with the Public Service Commission, LG&E was ordered to file a paper copy of the annual report information that it files with the Public Service Commission electronically, and include with such copy a paper copy of the notes to its financial statements that LG&E had previously filed as part of its FERC Form 2.

[1] *In the Matter of: Application of Louisville Gas and Electric Company for an Order Authorizing It To Cease Annual Filing of FERC Form 2*, Case No. 2008-00007.

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**
Louisville Gas and Electric Company	**End of** 2011/Q4

LOUISVILLE GAS AND ELECTRIC 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.

LOUISVILLE GAS AND ELECTRIC 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 INFORMATION NOT AVAILABLE
(A farm is any agricultural operating unit consisting of 3 acres of more)

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 11,846
(Located in Kentucky)

Total number of Miles of Pole line 7,174
(Located in Kentucky)

Name of Counties in which you furnish Electric Service:
(If additional space is required, add additional sheet)

BULLITT, HARDIN, HENRY, JEFFERSON, MEADE, OLDHAM, SHELBY, SPENCER and TRIMBLE

(A) Based on Standard Industrial Classification (SIC) Major Groups 01 (Agricultural Production-Crops) and and 02 (Agricultural Production Livestock and Animal Specialties).

Louisville Gas and Electric Company
Supplemental Electric Information
Revenues, Customers and KWH Sales
For Reporting Year 2011

	Revenues	KWHs Sold	Customers
440 Residential	$ 366,263,255	4,260,121,989	347,834
442 Commercial & Industrial Sales			
Small(or Commercial)	$ 300,002,319	3,708,744,195	41,529
Large (or Industrial)	$ 145,251,812	2,430,194,056	409
444 Public St. & Highway Lighting	$ 7,235,355	51,351,317	335
445 Other Sales to Public Authorities	$ 84,489,065	1,190,642,794	3,956
446 Sales to Railroads and Railways	$ -	-	-
448 Interdepartmental Sales	$ -	-	-
TOTAL Sales to Ultimate Customers	$ 903,241,806	11,641,054,351	394,063
447 Sales for Resale	$ 140,077,382	5,185,682,000	18
TOTAL Sales of Electricity	$1,043,319,188	16,826,736,351	394,081

THIS PAGE MUST BE COMPLETED AND RETURNED WITH THE ANNUAL REPORT

LOUISVILLE GAS AND ELECTRIC 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	717
3.	Total Part-Time and Temporary Employees	2
4.	Total Employees	719

Additional Requested Information

Utility Name Louisville Gas and Electric Company

FEIN# (Federal Employer Identification Number)

6	1	-	0	2	6	4	1	5	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: [X] 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**
Louisville Gas and Electric 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).

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FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Louisville Gas and Electric 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
Louisville Gas and Electric 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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	None
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	None
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	None
26	Transmission Service and Generation Interconnection Study Costs	231	None
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

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	
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	

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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)
67	Transmission Lines Added During the Year	424-425	
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	
70	Footnote Data	450	
	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 - July 2, 1913

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 and natural gas services in the City of Louisville and adjacent territory in Kentucky.

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 Louisville Gas and Electric 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 beneficieries for whom trust was maintained, and purpose of the trust.

Louisville Gas and Electric Company (LG&E) 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
Louisville Gas and Electric 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	355,938
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	188,837
7	Chief Financial Officer	S. Bradford Rives	177,028
8	Senior Vice President - Energy Services	Paul W. Thompson	180,771
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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 LG&E.

Schedule Page: 104 Line No.: 5 Column: b

John R. McCall's title was 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
Louisville Gas and Electric 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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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.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	Open Access Transmission Tariff (OATT)	
2	Attachment O	Docket No. ER11-2955
3		
4	OATT Schedule 1	Docket No. ER10-1509
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

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.

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None.

2. None.

3. In September 2011, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") 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. LG&E and KU will jointly acquire the assets as tenants in common, with LG&E and KU having 69% and 31% respective undivided interests. The purchase is subject to receipt of approvals from the Kentucky Public Service Commission, the Virginia State Corporation 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, 3.47 miles of transmission lines went into service. As these were interconnect transmission lines, no customers were added.

6. LG&E received FERC authorization in FERC Docket No. ES11-49-000 for up to $500 million in short-term debt through November 30, 2013. LG&E's money pool balance was zero and $12 million at December 31, 2011, and December 31, 2010, respectively.

   On November 1, 2010, LG&E entered into a new $400 million revolving credit facility maturing December 31, 2014. In October 2011, LG&E amended its syndicated credit facility. The amendment includes extending the expiration date from December 2014 to October 2016. Under this facility, LG&E 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. 2010-00205 on September 30, 2010. The balance outstanding under this line of credit was zero as of December 31, 2011, and $163 million as of December 31, 2010.

7. None.

8. During the first quarter of 2011, non-union employees received routine wage increases in accordance with annual salary reviews. In November 2011, LG&E and workers represented by IBEW Local 2100 entered into a 3 year collective bargaining agreement, which included wage increases consistent with market conditions.

9. See Notes 4 and 11 of Notes to Financial Statements.

10. None.

11. N/A

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12. See attached Notes to Financial Statements.

13. Edwin R. Staton was named Vice President of Transmission effective March 28, 2011. S. Bradford Rives was named Chief Administrative Officer and Kent W. 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. LG&E 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
Louisville Gas and Electric 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	4,679,879,565	4,361,375,745
3	Construction Work in Progress (107)	200-201	215,276,377	385,323,919
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		4,895,155,942	4,746,699,664
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,117,873,453	2,043,099,789
6	Net Utility Plant (Enter Total of line 4 less 5)		2,777,282,489	2,703,599,875
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)		2,777,282,489	2,703,599,875
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		2,139,990	2,139,990
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		75,240	75,240
19	(Less) Accum. Prov. for Depr. and Amort. (122)		63,360	63,360
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	594,286	594,286
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)		28,846,730	18,763,174
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	10,519
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		29,452,896	19,379,859
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		24,920,485	2,025,606
36	Special Deposits (132-134)		12,277	3,511,015
37	Working Fund (135)		20,090	20,090
38	Temporary Cash Investments (136)		33,064	100,406
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		61,816,182	70,841,405
41	Other Accounts Receivable (143)		12,953,835	15,999,128
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,835,907	2,258,397
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		10,916,898	29,799,791
45	Fuel Stock (151)	227	52,502,546	68,043,290
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	30,625,942	29,326,916
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	2,512	2,729

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	5,596,506	4,943,153
55	Gas Stored Underground - Current (164.1)		53,287,604	59,956,181
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		5,472,353	6,832,694
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		25,626	26,834
60	Rents Receivable (172)		3,241	4,695
61	Accrued Utility Revenues (173)		64,436,527	78,996,467
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		0	137,908
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	10,519
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)		320,789,781	368,299,392
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		9,845,015	9,448,909
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	406,124,035	357,713,680
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,007,070	852,033
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	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	550,300,832	600,334,947
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)		20,963,863	21,934,650
82	Accumulated Deferred Income Taxes (190)	234	90,900,667	127,207,382
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,079,141,482	1,117,491,601
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,208,806,638	4,210,910,717

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 Louisville Gas and Electric Company ("LG&E"). 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 LG&E of $1,702 million. The allocation of the LG&E 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	$ 546
Investments	1
Property, plant and equipment	2,935
Other intangible assets	183
Regulatory and other non-current assets	416
Current liabilities	(420)
Affiliated debt	(485)
Debt	(580)
Other non-current liabilities	(1,283)
Net identifiable assets acquired	1,313
Goodwill	389
Total purchase price	$ 1,702

Goodwill represents value paid for the rate regulated business of LG&E, 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. LG&E’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 LG&E’s assets and liabilities that contributed to goodwill were as follows:

The pollution control bonds, excluding the reacquired bonds, had a fair market value adjustment of $7 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 $87 million based upon an announced transaction by another owner. LG&E’s stock was valued at less than $1 million and the power purchase agreement has been valued at $87 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.

- LG&E recorded an emission allowance intangible asset and regulatory liability as the result of adjusting the fair value of the emission allowances at LG&E. The emission allowance fair value of $8 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. LG&E had previously recorded emission allowances as other materials and supplies. This emission allowance fair value adjustment is amortized as the emission allowances are consumed, which is expected to occur through 2040.

- LG&E recorded a coal contract intangible asset of $124 million and a non-current liability of $11 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 LG&E, 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, LG&E 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. LG&E's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

LG&E also considered whether a separate fair value should be assigned to LG&E's rights to operate within its various electric and natural gas 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.

Schedule Page: 110 Line No.: 40 Column: c

The balance in Customer Accounts Receivable (142) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value of Customer Accounts Receivable, LG&E netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of acquisition date. The fair value adjustment is amortized over the period accounts receivable are written off. See footnotes for Page 110, Line 42, Column c. The following reflects the purchase accounting adjustment:

Customer Accounts Receivable (142) Without Purchase Accounting	$ 61,816,182
Purchase Accounting Adjustment	(1,841,558)
2011 Amortization of Purchase Accounting Adjustment	920,778
2010 Amortization of Purchase Accounting Adjustment	920,780
Total for Customer Accounts Receivable (142)	$ 61,816,182

Schedule Page: 110 Line No.: 40 Column: d

The balance in Customer Accounts Receivable (142) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value of Customer Accounts Receivable, LG&E netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of acquisition date. The fair value adjustment is amortized over the period accounts receivable are written off. See footnotes for Page 110, Line 42, Column d. The following reflects the purchase accounting adjustment:

Customer Accounts Receivable (142) Without Purchase Accounting	$ 71,762,183
Purchase Accounting Adjustment	(1,841,558)
Amortization of Purchase Accounting Adjustment	920,780
Total for Customer Accounts Receivable (142)	$ 70,841,405

Schedule Page: 110 Line No.: 41 Column: c

The balance in Other Accounts Receivable (143) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value of Other Accounts Receivable, LG&E netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of acquisition date. The fair value adjustment is amortized over the period the accounts receivable are written off. See footnotes for Page 110, Line 42, Column c. The following reflects the purchase accounting adjustment:

Other Accounts Receivable (143) Without Purchase Accounting	$ 12,953,835
Purchase Accounting Adjustment	(1,768,320)
2011 Amortization of Purchase Accounting Adjustment	1,425,660
2010 Amortization of Purchase Accounting Adjustment	342,660
Total for Other Accounts Receivable (143)	$ 12,953,835

Schedule Page: 110 Line No.: 41 Column: d

The balance in Other Accounts Receivable (143) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value of Other Accounts Receivable, LG&E netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of acquisition date. The fair value adjustment is amortized over the period the accounts receivable are written off. See footnotes for Page 110, Line 42, Column d. The following reflects the purchase accounting adjustment:

Other Accounts Receivable (143) Without Purchase Accounting	$ 17,424,788
Purchase Accounting Adjustment	(1,768,320)
Amortization of Purchase Accounting Adjustment	342,660
Total for Other Accounts Receivable (143)	$ 15,999,128

Schedule Page: 110 Line No.: 42 Column: c

The balance in Accumulated Provision For Uncollectible Accounts (144) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value of Customer Accounts Receivable and Other Accounts Receivable, LG&E 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	$ 1,835,907
Purchase Accounting Adjustment	(3,609,878)
2011 Amortization of Purchase Accounting Adjustment	2,346,438
2010 Amortization of Purchase Accounting Adjustment	1,263,440

Total for Accum. Prov. for Uncollectible Acct. (144)	$	1,835,907

Schedule Page: 110 Line No.: 42 Column: d

The balance in Accumulated Provision For Uncollectible Accounts (144) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value of Customer Accounts Receivable and Other Accounts Receivable, LG&E 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	$	4,604,835
Purchase Accounting Adjustment		(3,609,878)
Amortization of Purchase Accounting Adjustment		1,263,440
Total for Accum. Prov. for Uncollectible Acct. (144)	$	2,258,397

Schedule Page: 110 Line No.: 44 Column: c

The decrease is due to intercompany tax settlements that were outstanding in 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 LG&E by PPL in November 2010, as these costs are considered to have no fair value in purchase accounting under US GAAP. However, since LG&E receives recovery of these costs in rates through the embedded cost of capital, the balance of $3,698,836 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 Expenses (181) Without Purchase Accounting	$	13,326,195
Purchase Accounting Adjustment		(3,698,836)
2011 Amortization of Purchase Accounting Adjustment		186,562
2010 Amortization of Purchase Accounting Adjustment		31,094
Total for Unamortized Debt Expenses (181)	$	9,845,015

Schedule Page: 110 Line No.: 69 Column: d

The balance in Unamortized Debt Expenses (181) was adjusted due to the purchase of LG&E by PPL in November 2010, as these costs are considered to have no fair value in purchase accounting under US GAAP. However, since LG&E receives recovery of these costs in rates through the embedded cost of capital, the balance of $3,698,836 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 Expenses (181) Without Purchase Accounting	$	13,116,651
Purchase Accounting Adjustment		(3,698,836)
Amortization of Purchase Accounting Adjustment		31,094
Total for Unamortized Debt Expenses (181)	$	9,448,909

First mortgage bonds were issued November 16, 2010, resulting in debt issuance expense of $5,424,700 to be amortized over the life of the related issues, of which $62,888 was amortized through December 31, 2010. A revolving credit facility was set up on November 1, 2010, resulting in setup fees of $4,256,182 to be amortized over the term of the credit facility, of which $169,085 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 LG&E 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	$ 397,110,901
Purchase Accounting Adjustment - unamortized debt expenses	3,698,836
2011 Amortization of Purchase Accounting Adjustment – unamortized debt expenses	(186,562)
2010 Amortization of Purchase Accounting Adjustment – unamortized debt expenses	(31,094)
Purchase Account Adjustment - interest rate swaps	2,050,000
2010 Amortization of Purchase Accounting Adjustment- interest rate swaps	(2,050,000)
Purchase Account Adjustment - coal supply contracts	11,265,929
2011 Amortization of Purchase Accounting Adjustment - coal supply contracts	(4,282,428)
2010 Amortization of Purchase Accounting Adjustment - coal supply contracts	(2,051,068)
Purchase Accounting Adjustment - rent commitments	794,713
2011 Amortization of Purchase Accounting Adjustment - rent commitments	(195,192)
Total for Other Regulatory Assets (182.3)	$ 406,124,035

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 LG&E 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, fair value of interest rate swaps based on the mark-to-market value for the swaps, 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	$ 344,036,364
Purchase Accounting Adjustment - unamortized debt expenses	3,698,836
Amortization of Purchase Accounting Adjustment - unamortized debt expenses	(31,094)
Purchase Account Adjustment - interest rate swaps	2,050,000
Amortization of Purchase Accounting Adjustment- interest rate swaps	(2,050,000)
Purchase Account Adjustment - coal supply contracts	11,265,929
Amortization of Purchase Accounting Adjustment - coal supply contracts	(2,051,068)
Purchase Accounting Adjustment - rent commitments	794,713
Total for Other Regulatory Assets (182.3)	$ 357,713,680

Schedule Page: 110 Line No.: 78 Column: c

The balance in Miscellaneous Deferred Debits (186) was adjusted due to the purchase of LG&E by PPL in November 1, 2010. The account was adjusted for coal supply contracts, a power purchase contract, emission allowances and goodwill attributed to LG&E. 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 LG&E's megawatt capacity. The value assigned to the purchase power contract was the difference between LG&E's original investment and the $87 million for LG&E. 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 allowances, ending in December 2040. 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	$ 473,638
Purchase Accounting Adjustment - power purchase contract	86,856,705
2011 Amortization of Purchase Accounting Adjustment - power purchase contract	(5,472,941)
2010 Amortization of Purchase Accounting Adjustment - power purchase contract	(1,047,496)
Purchase Accounting Adjustment - emission allowances	8,359,713
2011 Amortization of Purchase Accounting Adjustment - emission allowances	(5,419,213)
2010 Amortization of Purchase Accounting Adjustment - emission allowances	(926,313)
Purchase Accounting Adjustment - coal supply contracts	123,813,249
2011 Amortization of Purchase Accounting Adjustment - coal supply contracts	(39,340,574)
2010 Amortization of Purchase Accounting Adjustment - coal supply contracts	(6,153,288)
Goodwill	389,157,352
Total for Miscellaneous Deferred Debits (186)	$ 550,300,832

Schedule Page: 110 Line No.: 78 Column: d

The balance in Miscellaneous Deferred Debits (186) was adjusted due to the purchase of LG&E by PPL in November 1, 2010. The account was adjusted for coal supply contracts, a power purchase contract, emission allowances and goodwill attributed to LG&E. 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 LG&E's megawatt capacity. The value assigned to the purchase power contract was the difference between LG&E's original investment and the $87 million for LG&E. 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 allowances, ending in December 2040. 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	$ 275,027
Purchase Accounting Adjustment - power purchase contract	86,856,705
Amortization of Purchase Accounting Adjustment - power purchase contract	(1,047,496)
Purchase Accounting Adjustment - emission allowances	8,359,713
Amortization of Purchase Accounting Adjustment - emission allowances	(926,313)
Purchase Accounting Adjustment - coal supply contracts	123,813,249
Amortization of Purchase Accounting Adjustment - coal supply contracts	(6,153,288)
Goodwill	389,157,352
Rounding	(2)
Total for Miscellaneous Deferred Debits (186)	$ 600,334,947

Schedule Page: 110 Line No.: 82 Column: c

The balance in Accumulated Deferred Income Taxes (190) was adjusted due to the purchase of LG&E 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 rent commitment, 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 adjustment:

Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$ 23,826,072
Purchase Accounting Adjustment – pollution control bonds	2,558,343
2011 Amortization of Purchase Accounting Adjustment – pollution control bonds	(116,782)
2010 Amortization of Purchase Accounting Adjustment – pollution control bonds	(19,464)
Purchase Accounting Adjustment – power purchase contract	33,787,258
2011 Amortization of Purchase Accounting Adjustment – power purchase contract	(2,128,974)
2010 Amortization of Purchase Accounting Adjustment – power purchase contract	(407,476)
Purchase Accounting Adjustment - interest rate swaps	797,450
2010 Amortization of Purchase Accounting Adjustment - interest rate swaps	(797,450)
Purchase Accounting Adjustment – emission allowances	3,251,929
2011 Amortization of Purchase Accounting Adjustment – emission allowances	(2,108,074)
2010 Amortization of Purchase Accounting Adjustment – emission allowances	(360,336)
Purchase Accounting Adjustment – regulatory liability coal supply contracts	48,163,354
2011 Amortization of Purchase Accounting Adjustment – regulatory liability for coal supply contracts	(15,303,484)

2010 Amortization of Purchase Accounting Adjustment – regulatory liability for coal supply contracts	(2,393,629)
Purchase Accounting Adjustment – coal supply contracts	4,382,446
2011 Amortization of Purchase Accounting Adjustment – coal supply contracts	(1,665,864)
2010 Amortization of Purchase Accounting Adjustment – coal supply contracts	(797,865)
Purchase Accounting Adjustment – rent commitment	309,143
2011 Amortization of Purchase Accounting Adjustment – rent commitment	(65,083)
2010 Amortization of Purchase Accounting Adjustment – rent commitment	(10,847)
Total for Accumulated Deferred Income Taxes (190)	$ 90,900,667

Schedule Page: 110 Line No.: 82 Column: d

The balance in Accumulated Deferred Income Taxes (190) was adjusted due to the purchase of LG&E 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 rent commitment, 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 adjustment:

Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$ 38,744,526
Purchase Accounting Adjustment – pollution control bonds	2,558,343
Amortization of Purchase Accounting Adjustment – pollution control bonds	(19,464)
Purchase Accounting Adjustment – power purchase contract	33,787,258
Amortization of Purchase Accounting Adjustment – power purchase contract	(407,476)
Purchase Accounting Adjustment - interest rate swaps	797,450
Amortization of Purchase Accounting Adjustment - interest rate swaps	(797,450)
Purchase Accounting Adjustment – emission allowances	3,251,929
Amortization of Purchase Accounting Adjustment – emission allowances	(360,336)
Purchase Accounting Adjustment – regulatory liability coal supply contracts	48,163,354
Amortization of Purchase Accounting Adjustment – regulatory liability for coal supply contracts	(2,393,629)
Purchase Accounting Adjustment – coal supply contracts	4,382,446
Amortization of Purchase Accounting Adjustment – coal supply contracts	(797,865)
Purchase Accounting Adjustment – rent commitment	309,143
Amortization of Purchase Accounting Adjustment – rent commitment	(10,847)
Total for Accumulated Deferred Income Taxes (190)	$ 127,207,382

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Louisville Gas and Electric 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	425,170,424	425,170,424
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	1,277,667,368	1,277,667,368
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	835,889	835,889
11	Retained Earnings (215, 215.1, 216)	118-119	60,196,667	19,093,970
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
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)	0	0
16	Total Proprietary Capital (lines 2 through 15)		1,762,198,570	1,721,095,873
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,109,304,000	1,109,304,000
19	(Less) Reaquired Bonds (222)	256-257	0	163,200,000
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	6,226,470	6,526,682
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,668,458	3,948,318
24	Total Long-Term Debt (lines 18 through 23)		1,111,862,012	948,682,364
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)		5,691,293	4,121,200
29	Accumulated Provision for Pensions and Benefits (228.3)		184,133,495	213,591,951
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		31,046,877	13,686,199
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		23,968,832	17,943,789
34	Asset Retirement Obligations (230)		58,606,350	52,650,789
35	Total Other Noncurrent Liabilities (lines 26 through 34)		303,446,847	301,993,928
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	163,000,000
38	Accounts Payable (232)		97,848,808	104,974,357
39	Notes Payable to Associated Companies (233)		0	11,876,000
40	Accounts Payable to Associated Companies (234)		25,528,426	19,944,791
41	Customer Deposits (235)		22,361,042	23,237,609
42	Taxes Accrued (236)	262-263	13,284,850	9,598,153
43	Interest Accrued (237)		5,825,755	5,235,853
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2011/Q4

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)		1,090,154	1,275,524
48	Miscellaneous Current and Accrued Liabilities (242)		16,535,301	19,381,570
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		32,541,878	15,850,565
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		31,046,877	13,686,199
52	Derivative Instrument Liabilities - Hedges (245)		27,024,586	19,972,749
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		23,968,832	17,943,789
54	Total Current and Accrued Liabilities (lines 37 through 53)		187,025,091	362,717,183
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		7,307,169	8,580,930
57	Accumulated Deferred Investment Tax Credits (255)	266-267	42,718,844	45,524,576
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	10,652,321	15,658,759
60	Other Regulatory Liabilities (254)	278	219,287,438	262,328,918
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)		451,417,733	422,970,727
64	Accum. Deferred Income Taxes-Other (283)		112,890,613	121,357,459
65	Total Deferred Credits (lines 56 through 64)		844,274,118	876,421,369
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,208,806,638	4,210,910,717

Schedule Page: 112 Line No.: 7 Column: c

The balance in Other Paid-in Capital (208-211) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value, the balance was adjusted for the fixed rate pollution control bonds net of deferred taxes and goodwill. The balance also includes elimination of Retained Earnings (215, 215.1, 216) at October 31, 2010. See footnotes for 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	$ 83,581,499
Purchase Accounting Adjustment - fixed rate pollution control bonds	(4,018,374)
Purchase Accounting Adjustment - goodwill	389,157,352
Purchase Accounting Adjustment - prior retained earnings	808,946,891
Total for Other Paid-in Capital (208-211)	$ 1,277,667,368

Schedule Page: 112 Line No.: 7 Column: d

The balance in Other Paid-in Capital (208-211) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value, the balance was adjusted for the fixed rate pollution control bonds net of deferred taxes and goodwill. The balance also includes elimination of Retained Earnings (215, 215.1, 216) at October 31, 2010. The following reflects the purchase accounting adjustment:

Other Paid-in Capital (208-211) Without Purchase Accounting	$ 83,581,499
Purchase Accounting Adjustment - fixed rate pollution control bonds	(4,018,374)
Purchase Accounting Adjustment - goodwill	389,157,352
Purchase Accounting Adjustment - prior retained earnings	808,946,891
Total for Other Paid-in Capital (208-211)	$ 1,277,667,368

Schedule Page: 112 Line No.: 11 Column: c

The balance in Retained Earnings (215, 215.1, 216) was adjusted due to the purchase of LG&E 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; and Page 114, Line 62, Column c. The following reflects the purchase accounting adjustment:

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$ 868,929,557
Purchase Accounting Adjustment	(808,946,891)
2011 Amortization of Purchase Accounting Adjustment - rent commitment (net of deferred taxes of $(10,848))	(17,037)
2010 Amortization of Purchase Accounting Adjustment - rent commitment (net of deferred taxes of $10,848)	17,037
2011 Amortization of Purchase Accounting Adjustment - pollution control bonds (net of deferred taxes of $116,783)	183,429
2010 Amortization of Purchase Accounting Adjustment - pollution control bonds (net of deferred taxes of $19,463)	30,572
Total for Retained Earnings (215, 215.1, 216)	$ 60,196,667

Schedule Page: 112 Line No.: 11 Column: d

The balance in Retained Earnings (215, 215.1, 216) was adjusted due to the purchase of LG&E 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. The following reflects the purchase accounting adjustment:

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$ 827,993,252
Purchase Accounting Adjustment	(808,946,891)
Amortization of Purchase Accounting Adjustment - rent commitment (net of deferred taxes of $(10,848)	17,037
Amortization of Purchase Accounting Adjustment - pollution control bonds (net of deferred taxes of $19,463)	30,572
Total for Retained Earnings (215, 215.1, 216)	$ 19,093,970

Schedule Page: 112 Line No.: 19 Column: c

Available for sale bonds were remarketed during first quarter of 2011.

Schedule Page: 112 Line No.: 21 Column: c

The balance in Other Long-Term Debt (224) was adjusted due to the purchase of LG&E 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	6,576,717
2011 Amortization of Purchase Accounting Adjustment	(300,212)
2010 Amortization of Purchase Accounting Adjustment	(50,035)
Total for Other Long-Term Debt (224)	$ 6,226,470

Schedule Page: 112 Line No.: 21 Column: d

The balance in Other Long-Term Debt (224) was adjusted due to the purchase of LG&E 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	6,576,717
Amortization of Purchase Accounting Adjustment	(50,035)
Total for Other Long-Term Debt (224)	$ 6,526,682

Schedule Page: 112 Line No.: 37 Column: c

Prior balance represents drawdown on Wachovia Credit Facility for $163,000,000 in November 2010 paid off during first quarter of 2011.

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

The balance in Derivative Instrument Liabilities (244) was adjusted due to the purchase of LG&E by PPL in November 2010. The amount recorded ($1,570,000) reflects a credit valuation adjustment at the acquisition date. The following reflects the purchase accounting adjustment:

Derivative Instrument Liabilities (244) Without Purchase Accounting	$ 32,541,878
Purchase Accounting Adjustment	1,570,000
2010 Amortization of Purchase Accounting Adjustment	(1,570,000)
Total for Derivative Instrument Liabilities (244)	$ 32,541,878

Schedule Page: 112 Line No.: 50 Column: d

The balance in Derivative Instrument Liabilities (244) was adjusted due to the purchase of LG&E by PPL in November 2010. The amount recorded ($1,570,000) reflects a credit valuation adjustment at the acquisition date. The following reflects the purchase accounting adjustment:

Derivative Instrument Liabilities (244) Without Purchase Accounting	$ 15,850,565
Purchase Accounting Adjustment	1,570,000
Amortization of Purchase Accounting Adjustment	(1,570,000)
Total for Derivative Instrument Liabilities (244)	$ 15,850,565

Schedule Page: 112 Line No.: 52 Column: c

The balance in Derivative Instrument Liabilities - Hedging (245) was adjusted due to the purchase of LG&E by PPL in November 2010. The amount recorded ($480,000) reflects a credit valuation adjustment at the acquisition date. The following reflects the purchase accounting adjustment:

Derivative Instrument Liabilities - Hedging (245) Without Purchase Accounting	$ 27,024,586
Purchase Accounting Adjustment	480,000
2010 Amortization of Purchase Accounting Adjustment	(480,000)
Total for Derivative Instrument Liabilities - Hedging (245)	$ 27,024,586

Schedule Page: 112 Line No.: 52 Column: d

The balance in Derivative Instrument Liabilities - Hedging (245) was adjusted due to the purchase of LG&E by PPL in November 2010. The amount recorded ($480,000) reflects a credit valuation adjustment at the acquisition date. The following reflects the purchase accounting adjustment:

Derivative Instrument Liabilities - Hedging (245) Without Purchase Accounting	$ 19,972,749
Purchase Accounting Adjustment	480,000
Amortization of Purchase Accounting Adjustment	(480,000)
Total for Derivative Instrument Liabilities - Hedging (245)	$ 19,972,749

Schedule Page: 112 Line No.: 59 Column: c

The balance in Other Deferred Credits (253) was adjusted due to the purchase of LG&E 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	$ 5,120,368

Purchase Accounting Adjustment – coal supply contracts	11,265,929
2011 Amortization of purchase accounting adjustment - coal supply contracts	(4,282,428)
2010 Amortization of purchase accounting adjustment – coal supply contracts	(2,051,068)
Purchase Accounting Adjustment – rent commitment	794,713
2011 Amortization of purchase accounting adjustment - rent commitment	(167,308)
2010 Amortization of purchase accounting adjustment – rent commitment	(27,885)
Total for Other Deferred Credits (253)	$ 10,652,321

Schedule Page: 112 Line No.: 59 Column: d

The balance in Other Deferred Credits (253) was adjusted due to the purchase of LG&E 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 d. The following reflects the purchase accounting adjustments:

Other Deferred Credits (253) Without Purchase Accounting	$ 5,677,070
Purchase Accounting Adjustment – coal supply contracts	11,265,929
Amortization of purchase accounting adjustment – coal supply contracts	(2,051,068)
Purchase Accounting Adjustment – rent commitment	794,713
Amortization of purchase accounting adjustment – rent commitment	(27,885)
Total for Other Deferred Credits (253)	$ 15,658,759

Schedule Page: 112 Line No.: 60 Column: c

The balance in Other Regulatory Liabilities (254) was adjusted to reflect regulatory offset due to the purchase of LG&E 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 LG&E’s megawatt capacity. The value assigned to the purchase power contract was the difference between LG&E’s original investment and the $87 million for LG&E.

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	$ 58,617,596
Purchase Accounting Adjustment - coal supply contracts	123,813,249
2011 Amortization of Purchase Accounting Adjustment - coal supply contracts	(39,340,574)

2010 Amortization of Purchase Accounting Adjustment - coal supply contracts	(6,153,288)
Purchase Accounting Adjustment - emission allowances	8,359,713
2011 Amortization of Purchase Accounting Adjustment - emission allowances	(5,419,213)
2010 Amortization of Purchase Accounting Adjustment - emission allowances	(926,313)
Purchase Accounting Adjustment - power purchase contract	86,856,705
2011 Amortization of Purchase Accounting Adjustment - power purchase contract	(5,472,941)
2010 Amortization of Purchase Accounting Adjustment - power purchase contract	(1,047,496)
Total for Other Regulatory Liabilities (254)	$ 219,287,438

Schedule Page: 112 Line No.: 60 Column: d

The balance in Other Regulatory Liabilities (254) was adjusted to reflect regulatory offset due to the purchase of LG&E 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 LG&E’s megawatt capacity. The value assigned to the purchase power contract was the difference between LG&E’s original investment and the $87 million for LG&E.

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	$ 51,426,348
Purchase Accounting Adjustment - coal supply contracts	123,813,249
Amortization of Purchase Accounting Adjustment - coal supply contracts	(6,153,288)
Purchase Accounting Adjustment - emission allowances	8,359,713
Amortization of Purchase Accounting Adjustment - emission allowances	(926,313)
Purchase Accounting Adjustment - power purchase contract	86,856,705
Amortization of Purchase Accounting Adjustment - power purchase contract	(1,047,496)
Total for Other Regulatory Liabilities (254)	$ 262,328,918

Schedule Page: 112 Line No.: 64 Column: c

The balance in Accumulated Deferred Income Taxes - Other (283) was adjusted due to the purchase of LG&E by PPL in November 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 52, 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 - Other (283) Without Purchase Accounting	$ 48,238,115
Purchase Accounting Adjustment – power purchase contract	33,787,258
2011 Amortization of Purchase Accounting Adjustment - power purchase contract	(2,128,974)
2010 Amortization of Purchase Accounting Adjustment – power purchase contract	(407,476)
Purchase Accounting Adjustment – emission allowances	3,251,929
2011 Amortization of Purchase Accounting Adjustment - emission allowances	(2,108,074)
2010 Amortization of Purchase Accounting Adjustment – emission allowances	(360,336)
Purchase Accounting Adjustment – coal supply contracts	48,163,354
2011 Amortization of Purchase Accounting Adjustment - coal supply contracts	(15,303,484)
2010 Amortization of Purchase Accounting Adjustment – coal supply contracts	(2,393,629)
Purchase Accounting Adjustment – regulatory asset for coal supply contracts	4,382,446
2011 Amortization of Purchase Accounting Adjustment - regulatory asset for coal supply contracts	(1,665,864)
2010 Amortization of Purchase Accounting Adjustment – regulatory asset for coal supply contracts	(797,865)
Purchase Accounting Adjustment – rent commitment	309,143
2011 Amortization of Purchase Accounting Adjustment - rent commitment	(75,930)
Purchase Accounting Adjustment – interest rate swap	797,450
2010 Amortization of Purchase Accounting Adjustment – interest rate swap	(797,450)
Total for Accumulated Deferred Income Taxes - Other (283)	$ 112,890,613

Schedule Page: 112 Line No.: 64 Column: d

The balance in Accumulated Deferred Income Taxes - Other (283) was adjusted due to the purchase of LG&E by PPL in November 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 52, 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 - Other (283) Without Purchase Accounting	$ 35,422,635
Purchase Accounting Adjustment – power purchase contract	33,787,258
Amortization of Purchase Accounting Adjustment – power purchase contract	(407,476)
Purchase Accounting Adjustment – emission allowances	3,251,929
Amortization of Purchase Accounting Adjustment – emission allowances	(360,336)
Purchase Accounting Adjustment – coal supply contracts	48,163,354
Amortization of Purchase Accounting Adjustment – coal supply contracts	(2,393,629)
Purchase Accounting Adjustment – regulatory asset for coal supply contracts	4,382,446
Amortization of Purchase Accounting Adjustment – regulatory asset for coal supply contracts	(797,865)
Purchase Accounting Adjustment – rent commitment	309,143

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Purchase Accounting Adjustment – interest rate swap	797,450
Amortization of Purchase Accounting Adjustment – interest rate swap	(797,450)
Total for Accumulated Deferred Income Taxes - Other (283)	$ 121,357,459

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	1,364,324,725	1,318,558,923		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	833,403,806	818,724,773		
5	Maintenance Expenses (402)	320-323	116,359,069	111,701,105		
6	Depreciation Expense (403)	336-337	138,912,614	130,224,377		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	3,085,601	985,626		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	8,133,464	7,726,989		
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)		5,730,086	4,269,732		
14	Taxes Other Than Income Taxes (408.1)	262-263	28,121,584	22,571,624		
15	Income Taxes - Federal (409.1)	262-263	11,962,850	28,874,607		
16	- Other (409.1)	262-263	8,265,533	6,047,168		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	253,017,989	259,414,153		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	198,676,654	229,346,812		
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,805,732	-2,501,774		
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)		2,578	34,460		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		2,644,484	3,284,105		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,196,691,944	1,153,401,749		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		167,632,781	165,157,174		

Name of Respondent Louisville Gas and Electric 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)

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		Line No.
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)	
						1
1,059,750,303	1,015,611,567	304,574,422	302,947,356			2
						3
627,435,850	605,406,963	205,967,956	213,317,810			4
96,235,088	94,158,027	20,123,981	17,543,078			5
118,859,674	110,972,479	20,052,940	19,251,898			6
2,062,146	837,324	1,023,455	148,302			7
5,774,759	5,640,702	2,358,705	2,086,287			8
						9
						10
						11
						12
3,694,954	3,530,165	2,035,132	739,567			13
21,610,185	17,193,678	6,511,399	5,377,946			14
27,439,817	22,700,819	-15,476,967	6,173,788			15
9,971,422	5,404,750	-1,705,889	642,418			16
183,640,810	200,184,209	69,377,179	59,229,944			17
171,441,026	176,995,873	27,235,628	52,350,939			18
-2,670,412	-2,357,054	-135,320	-144,720			19
						20
						21
2,578	34,460					22
						23
1,632,808	2,692,840	1,011,676	591,265			24
916,853,589	882,274,239	279,838,355	271,127,510			25
142,896,714	133,337,328	24,736,067	31,819,846			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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)		167,632,781	165,157,174		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		150	2,175		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		21,101	22,971		
33	Revenues From Nonutility Operations (417)		1,217,684	1,386,069		
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		138,410	176,917		
38	Allowance for Other Funds Used During Construction (419.1)					
39	Miscellaneous Nonoperating Income (421)		1,049,402	-868,570		
40	Gain on Disposition of Property (421.1)		69,454	33,760		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		2,453,999	707,380		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,859,300	1,639,873		
46	Life Insurance (426.2)					
47	Penalties (426.3)		191			
48	Exp. for Certain Civic, Political & Related Activities (426.4)		920,562	956,348		
49	Other Deductions (426.5)		-654,496	-18,825,044		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		2,125,557	-16,228,823		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	3,168	2,541		
53	Income Taxes-Federal (409.2)	262-263	-489,148	-375,489		
54	Income Taxes-Other (409.2)	262-263	-90,284	-70,710		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	2,320,167	9,694,373		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,494,859	3,031,984		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-750,956	6,218,731		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		1,079,398	10,717,472		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		38,509,524	20,524,437		
63	Amort. of Debt Disc. and Expense (428)		2,098,127	453,375		
64	Amortization of Loss on Reaquired Debt (428.1)		1,213,346	1,211,251		
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)		9,663	23,582,997		
68	Other Interest Expense (431)		2,528,822	2,340,591		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)					
70	Net Interest Charges (Total of lines 62 thru 69)		44,359,482	48,112,651		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		124,352,697	127,761,995		
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)		124,352,697	127,761,995		

Schedule Page: 114 Line No.: 4 Column: c

The balance in Operation Expenses (401) was adjusted due to the purchase of LG&E 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	$ 833,375,921
Amortization of Purchase Accounting Adjustment	27,885
Total for Operation Expenses (401)	$ 833,403,806

Schedule Page: 114 Line No.: 4 Column: d

The balance in Operation Expenses (401) was adjusted due to the purchase of LG&E 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	$ 818,752,658
Amortization of Purchase Accounting Adjustment	(27,885)
Total for Operation Expenses (401)	$ 818,724,773

Schedule Page: 114 Line No.: 4 Column: g

The balance in Operation Expenses (401) was adjusted due to the purchase of LG&E 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	$ 627,413,263
Amortization of Purchase Accounting Adjustment	22,587
Total for Operation Expenses (401)	$ 627,435,850

Schedule Page: 114 Line No.: 4 Column: h

The balance in Operation Expenses (401) was adjusted due to the purchase of LG&E 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	$ 605,429,550
Amortization of Purchase Accounting Adjustment	(22,587)
Total for Operation Expenses (401)	$ 605,406,963

Schedule Page: 114 Line No.: 4 Column: i

The balance in Operation Expenses (401) was adjusted due to the purchase of LG&E 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	$ 205,962,658
Amortization of Purchase Accounting Adjustment	5,298
Total for Operation Expenses (401)	$ 205,967,956

Schedule Page: 114 Line No.: 4 Column: j

The balance in Operation Expenses (401) was adjusted due to the purchase of LG&E 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	$ 213,323,108
Amortization of Purchase Accounting Adjustment	(5,298)
Total for Operation Expenses (401)	$ 213,317,810

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 LG&E by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 228,816,570
Purchase Accounting Adjustment - coal contract	18,801,514
Purchase Accounting Adjustment - emission allowance	2,335,680
Purchase Accounting Adjustment - pensions	489,097
Purchase Accounting Adjustment - pollution control bonds	123,087
Purchase Accounting Adjustment - post retirement	20,328
Purchase Accounting Adjustment - OVEC	2,358,838
Purchase Accounting Adjustment - rent commitment	72,695
Purchase Accounting Adjustment - other	180
Total for Provision for Deferred Income Taxes (410.1)	$ 253,017,989

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 LG&E by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 259,382,206
Purchase Accounting Adjustment - pollution control bonds	20,514
Purchase Accounting Adjustment - rent commitment	11,433
Total for Provision for Deferred Income Taxes (410.1)	$ 259,414,153

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 LG&E by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 159,580,330

Purchase Accounting Adjustment - coal contract	18,801,514
Purchase Accounting Adjustment - emission allowance	2,335,680
Purchase Accounting Adjustment - pensions	391,278
Purchase Accounting Adjustment - pollution control bonds	97,854
Purchase Accounting Adjustment - post retirement	16,262
Purchase Accounting Adjustment - OVEC	2,358,838
Purchase Accounting Adjustment - rent commitment	58,883
Purchase Accounting Adjustment - other	171
Total for Provision for Deferred Income Taxes (410.1)	$ 183,640,810

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 LG&E by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 200,158,639
Purchase Accounting Adjustment - pollution control bonds	16,309
Purchase Accounting Adjustment - rent commitment	9,261
Total for Provision for Deferred Income Taxes (410.1)	$ 200,184,209

Schedule Page: 114 Line No.: 17 Column: i

The balance in Provision for Deferred Income Taxes (410.1) was adjusted due to the purchase of LG&E by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 69,236,240
Purchase Accounting Adjustment - pensions	97,819
Purchase Accounting Adjustment - pollution control bonds	25,233
Purchase Accounting Adjustment - post retirement	4,066
Purchase Accounting Adjustment - rent commitment	13,812
Purchase Accounting Adjustment - other	9
Total for Provision for Deferred Income Taxes (410.1)	$ 69,377,179

Schedule Page: 114 Line No.: 17 Column: j

The balance in Provision for Deferred Income Taxes (410.1) was adjusted due to the purchase of LG&E by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 59,223,567
Purchase Accounting Adjustment - pollution control bonds	4,205
Purchase Accounting Adjustment - rent commitment	2,172
Total for Provision for Deferred Income Taxes (410.1)	$ 59,229,944

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 LG&E by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 174,581,170
Purchase Accounting Adjustment - coal contract	18,801,514
Purchase Accounting Adjustment - emission allowance	2,335,680
Purchase Accounting Adjustment - pensions	489,097
Purchase Accounting Adjustment - pollution control bonds	6,304
Purchase Accounting Adjustment - post retirement	20,328

Purchase Accounting Adjustment - OVEC	2,358,838
Purchase Accounting Adjustment - rent commitment	83,543
Purchase Accounting Adjustment - other	180
Total for Provision for Deferred Income Taxes (411.1)	$ 198,676,654

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 LG&E by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 229,345,176
Purchase Accounting Adjustment - pollution control bonds	1,051
Purchase Accounting Adjustment - rent commitment	585
Total for Provision for Deferred Income Taxes (411.1)	$ 229,346,812

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 LG&E by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 147,464,602
Purchase Accounting Adjustment - coal contract	18,801,514
Purchase Accounting Adjustment - emission allowance	2,335,680
Purchase Accounting Adjustment - pensions	391,278
Purchase Accounting Adjustment - pollution control bonds	5,012
Purchase Accounting Adjustment - post retirement	16,262
Purchase Accounting Adjustment - OVEC	2,358,838
Purchase Accounting Adjustment - rent commitment	67,669
Purchase Accounting Adjustment - other	171
Total for Provision for Deferred Income Taxes (411.1)	$ 171,441,026

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 LG&E by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 176,994,563
Purchase Accounting Adjustment - pollution control bonds	835
Purchase Accounting Adjustment - rent commitment	475
Total for Provision for Deferred Income Taxes (411.1)	$ 176,995,873

Schedule Page: 114 Line No.: 18 Column: i

The balance in Provision for Deferred Income Taxes (411.1) was adjusted due to the purchase of LG&E by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 27,116,568
Purchase Accounting Adjustment - pensions	97,819
Purchase Accounting Adjustment - pollution control bonds	1,292
Purchase Accounting Adjustment - post retirement	4,066
Purchase Accounting Adjustment - rent commitment	15,874
Purchase Accounting Adjustment - other	9
Total for Provision for Deferred Income Taxes (411.1)	$ 27,235,628

Schedule Page: 114 Line No.: 18 Column: j

The balance in Provision for Deferred Income Taxes (411.1) was adjusted due to the purchase of LG&E by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 52,350,613
Purchase Accounting Adjustment - pollution control bonds	215
Purchase Accounting Adjustment - rent commitment	111
Total for Provision for Deferred Income Taxes (411.1)	$ 52,350,939

Schedule Page: 114 Line No.: 39 Column: d

The balance includes $915,784 unrealized energy trading and risk management derivative contract losses which is attributable to a change in the allocation between Louisville Gas and Electric and Kentucky Utilities Company and due to less activity from buy-backs of positions in 2010. In addition, the balance includes depreciation expense of $103,629 related to plant held for future use.

Schedule Page: 114 Line No.: 49 Column: c

Mark-to-market gain due to favorable pricing on forward transactions.

Schedule Page: 114 Line No.: 49 Column: d

The unrealized gains and losses of $30,550,884 previously recorded in other income and deductions related to the interest rate swaps which were reclassified to a regulatory asset.

Schedule Page: 114 Line No.: 62 Column: c

The balance in Interest on Long-Term Debt (427) was adjusted due to the purchase of LG&E 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	$ 38,809,736
Amortization of Purchase Accounting Adjustment	(300,212)
Total for Interest on Long-Term Debt (427)	$ 38,509,524

Schedule Page: 114 Line No.: 62 Column: d

The balance in Interest on Long-Term Debt (427) was adjusted due to the purchase of LG&E 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	$ 20,574,472
Amortization of Purchase Accounting Adjustment	(50,035)
Total for Interest on Long-Term Debt (427)	$ 20,524,437

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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		19,093,970	755,278,866
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			(808,946,891)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			(808,946,891)
16	Balance Transferred from Income (Account 433 less Account 418.1)		124,352,697	127,761,995
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			-83,250,000	(55,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-83,250,000	(55,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		60,196,667	19,093,970
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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)		60,196,667	19,093,970
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

BLANK

Schedule Page: 118 Line No.: 10 Column: d

The balance was adjusted due to the purchase of LG&E 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 LG&E 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; and Page 114, Line 62, Column c. The following reflects the purchase accounting adjustment:

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$ 868,929,557
Purchase Accounting Adjustment	(808,946,891)
2011 Amortization of Purchase Accounting Adjustment - rent commitment (net of deferred taxes of $(10,848))	(17,037)
2010 Amortization of Purchase Accounting Adjustment - rent commitment (net of deferred taxes of $10,848)	17,037
2011 Amortization of Purchase Accounting Adjustment - pollution control bonds (net of deferred taxes of $116,783)	183,429
2010 Amortization of Purchase Accounting Adjustment - pollution control bonds (net of deferred taxes of $19,463)	30,572
Total for Retained Earnings (215, 215.1, 216)	$ 60,196,667

Schedule Page: 118 Line No.: 38 Column: d

The balance in Retained Earnings (215, 215.1, 216) was adjusted due to the purchase of LG&E 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. The following reflects the purchase accounting adjustment:

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$ 827,993,252
Purchase Accounting Adjustment	(808,946,891)
Amortization of Purchase Accounting Adjustment - rent commitment (net of deferred taxes of $(10,848)	17,037
Amortization of Purchase Accounting Adjustment - pollution control bonds (net of deferred taxes of $19,463)	30,572
Total for Retained Earnings (215, 215.1, 216)	$ 19,093,970

Name of Respondent Louisville Gas and Electric 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)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	124,352,697	127,761,995
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	141,998,215	131,210,003
5	Amortization of Plant	8,133,464	7,726,989
6			
7			
8	Deferred Income Taxes (Net)	56,180,940	50,457,601
9	Investment Tax Credit Adjustment (Net)	-2,805,732	-2,501,774
10	Net (Increase) Decrease in Receivables	46,876,509	3,874,676
11	Net (Increase) Decrease in Inventory	20,608,814	-12,359,020
12	Net (Increase) Decrease in Allowances Inventory	217	1,442
13	Net Increase (Decrease) in Payables and Accrued Expenses	30,854,794	-56,166,889
14	Net (Increase) Decrease in Other Regulatory Assets	-52,954,507	-24,046,269
15	Net Increase (Decrease) in Other Regulatory Liabilities	7,191,248	-33,480,861
16	(Less) Allowance for Other Funds Used During Construction		
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-61,253,932	-10,996,169
19	Change in other deferred debits	2,071,209	1,976,680
20	Change in other deferred credits	-436,232	-2,350,629
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	320,817,704	181,107,775
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-165,322,128	-147,091,036
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	-14,380,688	-23,590,290
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction		
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-179,702,816	-170,681,326
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	69,454	34,434
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 Louisville Gas and Electric 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):	151,440,240	-1,213,170
54	Change in Non-Hedging Derivatives		1,897,960
55	Change in restricted cash	-9,400,674	
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-37,593,796	-169,962,102
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	-2,270,371	521,309,252
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	-174,876,000	4,475,600
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	-177,146,371	525,784,852
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-485,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-83,250,000	-55,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-260,396,371	-14,215,148
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	22,827,537	-3,069,475
87			
88	Cash and Cash Equivalents at Beginning of Period	2,126,012	5,195,487
89			
90	Cash and Cash Equivalents at End of period	24,953,549	2,126,012

Schedule Page: 120 Line No.: 18 Column: b

Other operating cash flows:

Depreciation charged to balance sheet accounts	$ (63,303,939)
Accumulated Provision for Uncollectible Accounts - Credit	(4,437,227)
Other changes in Net Utility Plant	57,816,038
Amortization of Debt Expenses and Losses on Bonds	3,031,613
Unamortized Discount on Long-Term Debt - Debit	279,860
Net decrease in Prepayments and other assets	854,588
Net increase in Preliminary Survey	(379,275)
Net decreases in Customer Advances for Construction	(1,968,922)
Net increase in Asset Retirement Obligations	5,955,561
Net increase in the Provision for Pension and Postretirement Benefits	34,082,372
Pension and Postretirement Funding	(70,274,658)
Net increase in Change in Non-Hedging Derivatives	1,417,874
Net increase in Other Liabilities	(24,731,049)
Gains and Losses on Interest Rate Swaps	1,679,862
Gains on Disposals of Assets	(69,454)
Proceeds received on the sale of assets	(1,040,785)
Change in Deferred Income Taxes - purchase accounting	105,935
Change in Deferred Regulatory Assets - purchase accounting	27,885
Change in Pollution Control Bonds - purchase accounting	(300,212)
Rounding	1

Total	$ (61,253,932)

Schedule Page: 120 Line No.: 18 Column: c

Other operating cash flows:

Depreciation charged to balance sheet accounts	$ (42,857,291)
Other changes in Net Utility Plant	3,777,797
Amortization of Debt Expenses and Losses on Bonds	1,664,626
Net decrease in Prepayments and other current assets	992,930
Net decrease in Preliminary Survey	740,526
Net increase in Other Comprehensive Income	10,454,766
Net decrease in Customer Advances for Construction	(1,040,271)
Net increase in Asset Retirement Obligations	9,187,084
Net increase in the Provision for Pension and Postretirement Benefits	34,415,448
Pension and Postretirement Funding	(26,813,841)
Net increase in Collateral Deposit for Interest Rate Swaps	(1,680,415)
Net increase in Change in Non-Hedging Derivatives	2,175,016
Gains and Losses on Interest Rate Swaps	(1,930,500)
Gains on Disposals of Assets	(33,760)
Proceeds received on the sale of assets	(673)
Change in Deferred Income Taxes - purchase accounting	30,311
Change in Long-Term Debt - purchase accounting	(50,035)
Change in Miscellaneous Long-Term Liabilities - purchase accounting	(27,885)
Rounding	(2)

Total	$ (10,996,169)

Schedule Page: 120 Line No.: 53 Column: b

Other investing cash flows:

Costs incurred related to Asset Retirement Obligations	$ (11,759,760)
Reissuance of Reacquired Pollution Control Bonds as available for sale securities	163,200,000

Total	$ 151,440,240

Schedule Page: 120 Line No.: 53 Column: c

Other investing cash flows:

Costs incurred related to Asset Retirement Obligations	$ (1,213,170)

Schedule Page: 120 Line No.: 90 Column: b

Cash and cash equivalents is comprised of the following amounts:

Cash (131)	$ 24,920,485
Temporary Cash Investments (136)	33,064

Total Cash and Cash Equivalents at the End of Period	$ 24,953,549

Schedule Page: 120 Line No.: 90 Column: c

Cash and cash equivalents is comprised of the following amounts:

Cash (131)	$ 2,025,606
Temporary Cash Investments (136)	100,406

Total Cash and Cash Equivalents at the End of Period	$ 2,126,012

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 affiliate of LG&E and 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 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 LG&E, KU 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 LG&E, 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 LG&E (Registration No. 333-173676) 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.

AOCI **-** accumulated other comprehensive income or loss.

ARO **-** asset retirement obligation.

Bluegrass CTs **-** Three natural gas combustion turbines owned by Bluegrass Generation. LG&E and KU 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.

***EBPB* -** Employee Benefit Plan Board. The administrator of PPL's U.S. qualified retirement plans, which is charged with the fiduciary responsibility to oversee and manage those plans and the investments associated with those plans.

***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.

***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.

***Fitch* -** Fitch, Inc., a credit rating agency.

***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.

kWh **-** kilowatt-hour, basic unit of electrical energy.

LG&E 2010 Mortgage Indenture **-** LG&E's Indenture, dated as of October 1, 2010, to The Bank of New York Mellon, as trustee, as supplemented.

LIBOR **-** London Interbank Offered Rate.

MATS **-** Mercury and Air Toxics Standards.

Moody's **-** Moody's Investors Service, Inc., a credit rating agency.

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.

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 LG&E pre-acquisition activity covering the time period prior to November 1, 2010.

S&P **-** Standard & Poor's Ratings Services, a credit rating agency.

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 LG&E 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.

***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.

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

LG&E is engaged in the regulated generation, transmission, distribution and sale of electricity. LG&E also engages in the regulated distribution and sale of natural gas.

The financial statements and accompanying footnotes of LG&E 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 LG&E 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 LG&E 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. LG&E consolidates a VIE when it is determined to have a controlling interest in the VIE, and thus is the primary beneficiary of the entity. LG&E 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. . Any noncontrolling interests are reflected in the financial statements.

The financial statements of LG&E 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

LG&E is a cost-based rate-regulated utility for which rates are set by regulators to enable LG&E to recover the costs of providing electric or gas 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." LG&E 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 LG&E's net income or equity.

Comprehensive Income

Comprehensive income includes net income and OCI. Comprehensive income is shown on the Statements of Comprehensive Income.

LG&E had an AOCI balance of $(10) million at December 31, 2009 (Predecessor period). During the ten months ended October 31, 2010 (a Predecessor period), LG&E had $10 million of after-tax gains on qualifying derivatives. There were no AOCI balances at December 31, 2010 and 2011 (Successor periods).

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. Interest rate contracts are used to hedge exposures to changes in the fair value of debt instruments and to hedge exposures to variability in expected cash flows associated with existing debt instruments or forecasted issuances of debt. 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, gas storage 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.

A similar process is also followed by the treasury department as it relates to interest rate derivatives. Examples of accounting guidelines provided to the treasury department staff include, but are not limited to:

- Transactions to lock in an interest rate prior to a debt issuance can be designated as cash flow hedges.
- Transactions entered into to hedge fluctuations in the fair value of existing debt can be designated as fair value hedges.
- Derivative transactions may be marked to fair value through regulatory assets/liabilities if approved by the appropriate regulatory body. These transactions generally include the effect of interest rate swaps that are included in customer rates.

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.

LG&E 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:

		Additions			
	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
2011 - Successor	$ 2	$ 5	$ -	$ 5	$ 2
2010 - Successor	-	1	2	1	2
2010 - Predecessor	2	4	-	4	2

(a) Primarily related to capital projects, thus the provision was recorded as an adjustment to construction work in progress.
(b) Includes amounts associated with LG&E 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 LG&E while the noncurrent portion is included in "Other noncurrent assets." At December 31, the balances of restricted cash and cash equivalents included the following.

	2011	2010
Margin deposits posted to counterparties (a)	$ -	$ 3
Cash collateral posted to counterparties (b)	29	19
Other	-	-
Total	$ 29	$ 22

(a) Deposits posted to counterparties associated with trading activities.
(b) Cash collateral posted to counterparties related to interest rate swap contracts.

Fair Value Measurements

LG&E 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. LG&E 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.

LG&E 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, LG&E'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.

Cost Method Investment

LG&E has an investment in OVEC, which is accounted for using the cost method. The investment is recorded in "Other noncurrent assets" on the LG&E Balance Sheet. LG&E 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 LG&E and 12 other companies affiliated with the various owners. LG&E owns 5.63% of OVEC's common stock. Pursuant to a power purchase agreement, LG&E is contractually entitled to its ownership percentage of OVEC's output, which is 134 MW.

LG&E’s investment in OVEC is not significant. The direct exposure to loss as a result of LG&E's involvement with OVEC is generally limited to the value of its investment; however, LG&E 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. LG&E records costs associated with planned major maintenance projects in the period in which the costs are incurred. LG&E 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.

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
$ 52	$ 9	$ 44	$ 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
$ 8	$ 1	$ 7

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 5.11% and 5.40% 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 LG&E'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, LG&E 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.

LG&E accounts for emission allowances as intangible assets. LG&E 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. LG&E 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

LG&E 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 LG&E, 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

LG&E 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 LG&E'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

LG&E sponsors and participates in qualified funded defined benefit pension plans and participates in a funded other postretirement benefit plan. These plans are applicable to the majority of the employees of LG&E. The plans LG&E participates in are sponsored by LKE. LKE allocates a portion of the liability and net periodic defined benefit pension and other postretirement costs of certain plans to LG&E based on its participation. LG&E 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.

LG&E and LKE use 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

LG&E is included in PPL's consolidated U.S. federal income tax return. Prior to PPL's acquisition of LKE, LG&E was included in E.ON US Investments Corp.'s consolidated U.S. federal income tax return.

Significant management judgment is required in developing LG&E'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. LG&E 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 LG&E 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.

LG&E records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. LG&E 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 LG&E 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 LG&E 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.

LG&E defers investment tax credits when the credits are utilized and amortizes the deferred amounts over the average lives of the related assets.

LG&E 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 LG&E is calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if LG&E 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. LG&E's intercompany tax receivable was $4 million at December 31, 2011 and 2010.

The provision for LG&E’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

LG&E 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

LG&E evaluates whether arrangements entered into contain leases for accounting purposes. See Note 8 for a discussion of arrangements under which LG&E is a lessee for accounting purposes.

Fuel, Materials and Supplies

Fuel, natural gas stored underground 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. For LG&E, natural gas supply costs are charged to expense as delivered to the distribution system. See Note 4 for further discussion of the fuel adjustment clause and gas supply clause.

"Fuel, materials and supplies" on the Balance Sheets consisted of the following at December 31.

	2011		2010	
Fuel	$	53	$	68
Natural gas stored underground (a)		53		60
Materials and supplies		36		34
Total	$	142	$	162

(a) The majority of LG&E's natural gas stored underground is held to serve native load.

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, LG&E 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.

LG&E 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 LG&E.

2. Preferred Securities

LG&E is authorized to issue up to 1,720,000 shares of preferred stock at a $25 par value and 6,750,000 shares of preferred stock without par value. LG&E had no preferred stock issued or outstanding in 2011 or 2010.

3. Income and Other Taxes

The provision for LG&E's deferred income taxes for regulated assets is based upon the ratemaking principles reflected in rates established by the KPSC 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 LG&E's deferred income tax assets and liabilities were as follows:

	2011	2010
Deferred Tax Assets		
Regulatory liabilities and other	$ 65	$ 86
Deferred investment tax credit (a)	17	8
Income taxes due to customers	23	25
Liabilities and other	10	10
Total deferred tax assets	115	129
Deferred Tax Liabilities		
Plant - net	462	422
Regulatory assets and other	107	108
Accrued pension costs	19	16
Total deferred tax liabilities	588	546
Net deferred tax liability	$ 473	$ 417

(a) Changes in balance primarily relate to investment tax credits for TC2, which began dispatching electricity in January 2011. See discussion on TC2 below.

LG&E 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	$ 12	$ (4)
Current - State	8	1
Total Current Expense	20	(3)
Deferred - Federal	52	12
Deferred - State	2	1
Total Deferred Expense	54	13
Investment tax credit, net - Federal	(3)	-
Total income tax expense (a)	$ 71	$ 10
Total income tax expense - Federal	$ 61	$ 8
Total income tax expense - State	10	2
Total income tax expense (a)	$ 71	$ 10

	Predecessor
	Ten Months Ended October 31, 2010
Income Tax Expense (Benefit)	
Current - Federal	$ 32
Current - State	5
Total Current Expense	37
Deferred - Federal	21
Deferred - State	2
Total Deferred Expense	23
Investment tax credit, net - Federal	(2)
Total income tax expense (a)	$ 58
Total income tax expense - Federal	$ 51
Total income tax expense - State	7
Total income tax expense (a)	$ 58

(a) Excludes deferred federal and state tax expense recorded to OCI of $7 million for the ten month period ended October 31, 2010. Also excludes deferred federal and state tax expense recorded to Regulatory assets of $2 million in 2011, $1 million for the two month period ended December 31, 2010 and $6 million for the ten month period ended October 31, 2010.

	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%	$ 68	$ 10
Increase (decrease) due to:		
State income taxes, net of federal income tax benefit	7	1
Other	(4)	(1)
Total increase (decrease)	3	-
Total income tax expense	$ 71	$ 10
Effective income tax rate	36.4%	34.5%

	Predecessor
	Ten Months Ended October 31, 2010
Reconciliation of Income Taxes	
Federal income tax on Income Before Income Taxes at statutory tax rate - 35%	$ 58
Increase (decrease) due to:	
State income taxes, net of federal income tax benefit	4
Other	(4)
Total increase (decrease)	-
Total income tax expense	$ 58
Effective income tax rate	34.7%

	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	$ 18	$ 1	$ 12

In June 2006, LG&E and KU filed a joint application with the DOE requesting certification to be eligible for $125 million in investment tax credits ($24 million to LG&E and $101 million to KU) applicable to the construction of TC2. All necessary DOE and IRS approvals were subsequently received. In September 2007, LG&E and KU 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 LG&E and KU.

Unrecognized Tax Benefits

LG&E's unrecognized tax benefits and changes in those unrecognized tax benefits are insignificant at December 31, 2011 and 2010. For LG&E, 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 LG&E.

At December 31, 2011 and 2010, the receivable (payable) balances were recorded for interest related to tax positions. The amounts for LG&E were insignificant. The interest expense (benefit) was recognized in income taxes. The amount for LG&E was insignificant.

Tax Jurisdictions

The income tax provisions for LG&E 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. LG&E 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 LG&E, 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, LG&E 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.

LG&E is subject to the jurisdiction of the KPSC and FERC.

LG&E's 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. LG&E 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. LG&E's customer rates will continue to reflect the original contracted prices for these contracts.

The following tables provide information about the regulatory assets and liabilities of cost-based rate-regulated utility operations.

	2011	2010
Current Regulatory Assets:		
ECR	$ -	$ 5
Coal contracts (a)	-	1
Gas supply clause	6	4
Fuel adjustment clause	3	3
Total current regulatory assets	$ 9	$ 13
Noncurrent Regulatory Assets:		
Defined benefit plans	$ 225	$ 213
Storm costs	66	65
Unamortized loss on debt	21	22
Interest rate swaps	69	43
Coal contracts (a)	5	8
AROs	11	7
Other	6	9
Total noncurrent regulatory assets	$ 403	$ 367

Current Regulatory Liabilities:				
Coal contracts (a)	$	-	$	31
Gas supply clause		6		9
Other		4		11
Total current regulatory liabilities	$	10	$	51
Noncurrent Regulatory Liabilities:				
Coal contracts (a)	$	78	$	87
Power purchase agreement - OVEC (a)		80		86
Net deferred tax assets		31		34
Other		3		1
Total noncurrent regulatory liabilities	$	192	$	208

(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, $21 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

LG&E has the ability to request from the KPSC 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, LG&E 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 2035 for LG&E.

ECR

Kentucky law permits LG&E 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. LG&E 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, LG&E'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.

Gas Supply Clause

LG&E's natural gas rates contain a gas supply clause, whereby the expected cost of natural gas supply and variances between actual and expected costs from prior periods are adjusted quarterly in LG&E's rates, subject to approval by the KPSC. The gas supply clause includes a separate natural gas procurement incentive mechanism, a performance-based rate, which allows LG&E's rates to be adjusted annually to share variances between actual costs and market indices between the shareholders and the customers during each performance-based rate year (12 months ending October 31). The regulatory assets or liabilities represent the total amounts that have been under- or over-recovered due to timing or adjustments to the mechanisms and are recovered within 18 months.

Fuel Adjustments

LG&E's retail electric 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 LG&E'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.

Interest Rate Swaps

Because realized amounts associated with LG&E's interest rate swaps, including a terminated swap contract, are recoverable through rates based on an Order from the KPSC, LG&E's unrealized gains and losses are recorded as a regulatory asset or liability until they are realized as interest expense. Interest expense from existing swaps is realized and recovered over the terms of the associated debt, which matures through 2033. Amortization of the gain/loss related to the terminated swap contract is recovered through 2035 as approved by the KPSC.

In the third quarter of 2010, LG&E recorded a pre-tax gain to reverse previously recorded losses of $21 million and $9 million to reflect the reclassification of its ineffective swaps and terminated swap to regulatory assets based on an Order from the KPSC in the 2010 rate case whereby the cost of LG&E's terminated swap was allowed to be recovered in base rates. Previously, gains and losses on interest rate swaps designated as effective cash flow hedges were recorded within other comprehensive income and common equity. The gains and losses on the ineffective portion of interest rate swaps designated as cash flow hedges were recorded to earnings monthly, as was the entire change in the market value of the ineffective swaps.

<u>AROs</u>

As noted in Note 1, the accretion and depreciation related to LG&E'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.

<u>DSM</u>

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. LG&E'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 LG&E 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.

<u>Power Purchase Agreement - OVEC</u>

As a result of purchase accounting associated with PPL's acquisition of LKE, LG&E'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.

<u>Regulatory Liability Associated with Net Deferred Tax Assets</u>

LG&E'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, LG&E 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. LG&E requested $1.4 billion to modernize the sulfur dioxide scrubbers at the Mill Creek generating plant as well as install fabric-filter baghouse systems for increased particulate and mercury control on all units at the Mill Creek generating plant and on Unit 1 at the Trimble County generating plant.

In November 2011, LG&E and KU filed a joint unanimous settlement agreement, stipulation and recommendation with the KPSC. In December 2011, LG&E and KU 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 LG&E and KU 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 $1.4 billion at LG&E and $900 million at KU. 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. 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, LG&E and KU 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. LG&E and KU are awaiting the KPSC Staff report, which will close this proceeding.

CPCN Filing

In September 2011, LG&E and KU filed a CPCN with the KPSC requesting approval to build a 640 MW

NGCC at the existing Cane Run plant site. LG&E will own a 22% undivided interest, and KU will own a 78% undivided interest in the new NGCC. In addition, LG&E and KU also requested approval to purchase the Bluegrass CTs which are expected to provide up to 495 MW of peak generation supply. LG&E will own a 69% undivided interest, and KU will own a 31% undivided interest in the purchased assets. In conjunction with these developments, at the end of 2015, LG&E anticipates retiring three coal-fired generating units at its Cane Run plant. These generating units represent 563 MW of combined summer capacity.

LG&E anticipates that the NGCC construction and the acquisition of the Bluegrass CTs could require up to $300 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 LG&E and KU would commit that no base rate increases would take effect before January 1, 2013. Under the terms of the settlement, LG&E and KU 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, LG&E and KU agreed to implement the Acquisition Savings Sharing Deferral (ASSD) methodology whereby LG&E's and KU's adjusted jurisdictional revenues, expenses, and net operating income are calculated each year. If LG&E's or KU'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, LG&E and KU have not recognized any impact of the ASSD in the financial statements as of December 31, 2011. The ASSD methodology for each of LG&E's and KU'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

LG&E operates under a FERC-approved open access transmission tariff. LG&E 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. LG&E 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 August 2011, a strong storm hit LG&E's service area causing significant damage and widespread outages for approximately 139,000 customers. LG&E filed an application with the KPSC in September 2011 requesting approval of a regulatory asset recorded to defer, for future recovery, $8 million in incremental operation and maintenance expenses related to the storm restoration. An Order was received in December 2011 granting regulatory accounting treatment, while recovery of the regulatory asset will be determined within the next base rate case.

In September 2009, the KPSC approved the deferral of $44 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 $24 million of costs associated with high winds from the remnants of Hurricane Ike in September 2008. LG&E 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, LG&E 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.

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

	December 31, 2010	
	Borrowed (a)	Letters of Credit Issued
Syndicated Credit Facility (b) (c) (d)	$ 163	$ -

(a) Amounts borrowed are recorded as "Short-term debt" on the Balance Sheets.

(b) In October 2011, LG&E amended its credit facility. The amendments include extending the expiration dates from December 2014 to October 2016. Under this credit facility, LG&E continues to have the ability to make cash borrowings and request the lenders to issue letters of credit.

(c) In June 2011, this facility was amended such that the fees and the spreads to benchmark interest rates for borrowings depend upon LG&E's senior secured long-term debt rating rather than the senior unsecured long-term debt rating. The facility contains a financial covenant requiring LG&E's debt to total capitalization not to exceed 70%, as calculated in accordance with the facility, and other customary covenants. Additionally, subject to certain conditions, LG&E may request that the facility's capacity be increased by up to $100 million.

(d) The borrowing outstanding at December 31, 2010 bore interest at 2.27%. Such borrowing was repaid in January 2011 with proceeds received from the remarketing of certain tax-exempt bonds that were held by LG&E at December 31, 2010.

In February 2012, LG&E 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 LG&E's Syndicated Credit Facility.

See Note 12 for discussion of intercompany borrowings.

Long-term Debt

	2011 (a)	2010
Senior Secured/First Mortgage Bonds (b)	$ 535	$ 535
Pollution Control Bonds (Collateral Series), due 2023-2037 (c)	574	574
Fair value adjustments from purchase accounting (d)	6	7
Unamortized discount	(3)	(4)
Total Long-term Debt	$ 1,112	$ 1,112

(a) Aggregate maturities of long-term debt are zero for each of 2012 through 2014; 2015, $250; 2016, $0; and $859 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.

LG&E's first mortgage bonds are secured by the lien of the LG&E 2010 Mortgage Indenture, which creates a lien, subject to certain exceptions and exclusions, on substantially all of LG&E'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 and the storage and distribution of natural gas. The aggregate carrying value of the property subject to the lien was $2.6 billion and $2.5 billion at December 31, 2011 and December 31, 2010.

The LG&E 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, LG&E 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, LG&E 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 LG&E 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 LG&E. The related revenue bond documents allow LG&E 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 LG&E that were in a term rate mode totaled $294 million. The weighted average rate on these bonds was 3.37%. At December 31, 2010, the amounts that were in a term rate mode totaled $156 million. The weighted average rate on these bonds was 5.22%.

At December 31, 2011, the aggregate tax-exempt revenue bonds issued on behalf of LG&E that were in a variable rate mode totaled $280 million. The weighted average rate on these bonds was 0.33%. At December 31, 2010, the amounts that were in a variable rate mode totaled $418 million. The weighted average rate on these bonds was 0.55%.

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, $135 million are in the form of insured auction rate securities, wherein interest rates are reset either weekly or 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 LG&E 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 LG&E to convert the bonds to other interest rate modes.

Certain variable rate tax-exempt revenue bonds totaling $120 million at December 31, 2011, are subject to tender for purchase by LG&E at the option of the holder and to mandatory tender for purchase by LG&E upon the occurrence of certain events. At December 31, 2010, LG&E held $163 million of such bonds, which were issued on its behalf by Louisville/Jefferson County, Kentucky and are reflected as "Short-term investments" on the Balance Sheet. In January 2011, the entire $163 million of bonds were remarketed to unaffiliated investors in a term rate mode, bearing interest at 1.90% into 2012. The proceeds from the remarketing were used to repay the borrowing under LG&E's syndicated credit facility, which is discussed above in "Credit Arrangements and Short-term Debt."

(d) Reflects adjustments made to record LG&E's long-term debt at fair value at the time of acquisition of LKE in 2010.

Distributions, Capital Contributions and Related Restrictions

LG&E 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. LG&E 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. However, Orders from the KPSC require LG&E to obtain prior regulatory consent or approval before loaning funds to PPL. At December 31, 2011, the net restricted assets of LG&E were approximately $1.7 billion.

During the year ended December 31, 2011, LG&E paid dividends of $83 million to its parent, LKE. No capital contributions were received from LKE during this period.

In February 2012, LG&E 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 LG&E by $809 million. LG&E does not anticipate changing its dividend practices.

6. Acquisitions, Development and Divestitures

LG&E 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, LG&E and KU 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, LG&E and KU will jointly acquire the Bluegrass CTs as tenants in common, with LG&E as owner of a 69% undivided interest, and KU as owner of a 31% 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, LG&E and KU 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, LG&E and KU 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, LG&E 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, LG&E issued debt totaling $531 million. The majority of these proceeds, together with a borrowing by LG&E under its available credit facilities, were 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 $1,702 million for LG&E. 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	$ 503
Investments	1
PP&E	2,935
Other intangibles (current and noncurrent)	226
Regulatory and other noncurrent assets	416
Current liabilities, excluding current portion of long-term debt	(420)
PPL affiliate indebtedness	(485)
Long-term debt (current and noncurrent)	(580)
Other noncurrent liabilities	(1,283)
Net identifiable assets acquired	1,313
Goodwill	389
Net assets acquired and beginning equity balance on November 1, 2010	$ 1,702

Goodwill represents value paid for the rate regulated businesses of LG&E, 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. LG&E'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 LG&E's assets and liabilities that contributed to goodwill are as follows:

The pollution control bonds, excluding the reacquired bonds, had a fair value adjustment of $7 million for LG&E. 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. LG&E's investment in OVEC was not significant and the power purchase agreement was valued at $87 million for LG&E. 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.

- LG&E recorded an emission allowance intangible asset and a regulatory liability as the result of adjusting the fair value of the emission allowances at LG&E. The emission allowance intangible of $8 million at LG&E 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. LG&E 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 LG&E for $124 million as well as a non-current liability of $11 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 LG&E, 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 $2 million in the liability balances of LG&E 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, LG&E 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. LG&E's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

LG&E also considered whether a separate fair value should be assigned to LG&E's rights to operate within its various electric and natural gas 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

LG&E and KU 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, LG&E and KU entered into an 18-year lease of the turbines. LG&E and KU 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 LG&E and KU 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, LG&E and KU 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 LG&E and KU. The maximum aggregate amount at December 31, 2011 that could be required to be paid by LG&E is $2 million and by KU is $4 million. LKE has guaranteed the payment of these potential default payments of LG&E and KU.

Other Leases

LG&E has entered into various agreements for the lease of office space, vehicles, land, gas storage 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
$ 7	$ 1	$ 5

Total future minimum rental payments for all operating leases are estimated to be:

2012	$ 5
2013	5
2014	4
2015	3
2016	1
Thereafter	1
Total	$ 19

9. Retirement and Postemployment Benefits

Defined Benefits

LG&E sponsors the Louisville Gas and Electric Company Bargaining Employees' Retirement Plan. In addition to the plan it sponsors, LG&E is allocated a portion of the funded status and costs of certain defined benefit plans sponsored by LKE based on its participation in those plans, which management believes are reasonable. The actuarially determined obligations of current active employees and retired employees are used as a basis to allocate total plan activity, including active and retiree costs and obligations. LG&E's allocated share of the funded status of the pension plans resulted in a liability of $53 million and $69 million at December 31, 2011 and 2010. LG&E's allocated share of other postretirement benefits was a liability of $87 million and $85 million at December 31, 2011 and 2010.

The defined benefit pension plans of LKE and its subsidiaries, including LG&E, 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 following table provides the components of net periodic benefit cost for LG&E's pension benefit plan 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	
	Successor	
	2011	2010
Net periodic defined benefit costs (credits):		
Service cost	$ 2	$ -
Interest cost	14	2
Expected return on plan assets	(18)	(3)
Amortization of:		
Prior service cost	2	1
Actuarial loss	11	2
Net periodic defined benefit costs	$ 11	$ 2
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets - Gross:		
Current year net (gain) loss	$ 15	$ (5)
Current year prior service cost	9	-
Amortization of:		
Prior service cost	(2)	-
Actuarial (loss)	(11)	(2)
Total recognized in regulatory assets	11	(7)
Total recognized in net periodic benefit costs and regulatory assets	$ 22	$ (5)

	Pension Benefits
	Predecessor
	2010
Net periodic defined benefit costs (credits):	
Service cost	$ 1
Interest cost	12
Expected return on plan assets	(13)
Amortization of:	
Prior service cost	2
Actuarial loss	6
Net periodic defined benefit costs	$ 8
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets - Gross:	
Current year net (gain) loss	$ 18
Amortization of:	
Prior service cost	(2)
Actuarial (loss)	(6)
Total recognized in regulatory assets	10
Total recognized in net periodic benefit costs and regulatory assets	$ 18

The estimated amounts to be amortized from regulatory assets into net periodic benefit costs for LG&E in 2012 are as follows.

	Pension Benefits
Prior service cost	$ 2
Actuarial loss	10
Total	$ 12

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
$ 16	$ 3	$ 12

Other Postretirement Benefits (a)

Successor		Predecessor
2011	2010	2010
$ 5	$ 1	$ 4

(a) Includes costs for the specific plans it sponsors and allocated costs of defined benefit plans sponsored by LKE, based on its participation in those plans.

The following table provides defined benefit costs allocated from LKE.

Pension Benefits		
Successor		Predecessor
2011	2010	2010
$ 7	$ 1	$ 6

Other Postretirement Benefits		
Successor		Predecessor
2011	2010	2010
$ 5	$ 1	$ 4

The following table provides the weighted-average assumptions used in the valuation of the benefit obligations at December 31, 2011 and 2010, for the Successor, and at October 31, 2010, for the Predecessor.

	Pension Benefits		
	Successor		Predecessor
	2011	2010	2010
Discount rate	5.00%	5.39%	5.32%
Rate of compensation increase	N/A	N/A	N/A

The following table provides the weighted-average assumptions used to determine the net periodic benefit costs 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		
	Successor		Predecessor
	2011	2010	2010
Discount rate	5.39%	5.28%	6.08%
Rate of compensation increase	N/A	N/A	N/A
Expected return on plan assets (a)	7.25%	7.25%	7.75%

(a) The expected long-term rates of return for LG&E's pension and other postretirement benefits have been developed using a best-estimate of expected returns, volatilities and correlations for each asset class. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes. LG&E management corroborates these rates with expected long-term rates of return calculated by its independent actuary, who uses a building block approach that begins with a risk-free rate of return with factors being added such as inflation, duration, credit spreads and equity risk. Each plan's specific asset allocation is also considered in developing a reasonable return assumption.

The funded status of the LG&E plan was as follows 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			
	Successor			
	2011		2010	
Change in Benefit Obligation				
Benefit Obligation, beginning of period	$	274	$	276
Service cost		2		-
Interest cost		14		2
Plan amendments		9		-
Actuarial loss		14		(2)
Gross benefits paid		(15)		(2)
Benefit Obligation, end of period		298		274
Change in Plan Assets				
Plan assets at fair value, beginning of period		217		214
Actual return on plan assets		16		6
Employer contributions		38		-
Actual expenses paid		(15)		-
Gross benefits paid		-		(3)
Plan assets at fair value, end of period		256		217
Funded Status, end of period	$	(42)	$	(57)
Amounts recognized in the Balance Sheets consist of:				
Noncurrent liability	$	(42)	$	(57)
Net amount recognized, end of period	$	(42)	$	(57)
Amounts recognized in regulatory assets (pre-tax) consists of:				
Prior service cost	$	20	$	13
Net actuarial loss		115		111
Total	$	135	$	124
Total accumulated benefit obligation for defined benefit pension plan	$	292	$	274

		Pension Benefits Predecessor 2010
Change in Benefit Obligation		
Benefit Obligation, beginning of period	$	251
Service cost		2
Interest cost		12
Plan amendments		-
Actuarial loss		24
Gross benefits paid		(13)
Benefit Obligation, end of period		276
Change in Plan Assets		
Plan assets at fair value, beginning of period		196
Actual return on plan assets		19
Employer contributions		12
Actual expenses paid		-
Gross benefits paid		(13)
Plan assets at fair value, end of period		214
Funded Status, end of period	$	(62)
Amounts recognized in the Balance Sheets consist of:		
Noncurrent liability	$	(62)
Net amount recognized, end of period	$	(62)
Amounts recognized in regulatory assets (pre-tax) consists of:		
Prior service cost	$	14
Net actuarial loss		118
Total	$	132
Total accumulated benefit obligation for defined benefit pension plan	$	273

LG&E's pension plan had projected and accumulated benefit obligations in excess of plan assets at December 31, 2011 and 2010.

Plan Assets - Pension Plans

The investment policies of the Louisville Gas and Electric Company Bargaining Employees' Retirement Plan trust (LG&E pension trust) outline allowable investments and define the responsibilities of the EBPB and the external investment managers. The only prohibited investments are investments in debt or equity securities issued by PPL and its subsidiaries or PPL's pension plan consultant. Derivative instruments may be utilized as a cost-effective means to mitigate risk and match the duration of investments to projected obligations. The investment policies are reviewed annually by PPL's Board of Directors.

The EBPB created a risk management framework around the trust assets and pension liabilities. This framework considers the trust assets as being composed of three sub-portfolios: the growth, immunizing and liquidity portfolios. The growth portfolio is comprised of investments that generate a return at a reasonable risk, including equity securities, certain debt securities and alternative investments. The immunizing portfolio consists of debt securities and derivative positions that will typically have long durations. The immunizing portfolio is designed to offset a portion of the change in the pension liabilities due to changes in interest rates. The liquidity portfolio consists primarily of cash and cash equivalents.

Target allocation ranges have been developed for each portfolio based on input from external consultants with a goal of limiting funded status volatility. The EBPB monitors the investments in each portfolio, and seeks to obtain a target portfolio that emphasizes reduction of risk of loss from market volatility. In pursuing that goal, the EBPB establishes revised guidelines from time to time.

The asset allocation for the trusts and the target allocation by portfolio, at December 31 are as follows.

LG&E Pension Trust

	Percentage of Trust Assets	Target Range	Target Asset Allocation
	2011	2011	2011
Growth Portfolio	**51%**	**45 - 60%**	**59%**
Equity securities	33%		
Debt securities (a)	18%		
Immunizing Portfolio	**36%**	**35 - 55%**	**38%**
Debt securities (a) (b)	36%		
Liquidity Portfolio (b)	**13%**	**0 - 9%**	**3%**
Total	100%		100%

(a) Includes commingled debt funds, which LG&E treats as debt securities for asset allocation purposes.
(b) The asset allocation for this portfolio is not within the established target range due to the transition of assets at the end of 2011 in anticipation of a transfer into the PPL Services Corporation Master Trust in January 2012.

Prior to the fourth quarter of 2011, the LG&E pension trust was managed using a different investment policy.

As of December 31, 2010, the asset allocation was as follows.

	Percentage of Trust Assets 2010	Target Range 2010
Asset Class		
Equity securities	57%	45 - 75%
Debt securities (a)	43%	30 - 50%
Other	0%	0 - 10%
Total	100%	

(a) Includes commingled debt funds.

The fair value of net assets in the LG&E pension trust by asset class and level within the fair value hierarchy was:

	December 31, 2011			
	Total	Level 1	Level 2	Level 3
LG&E Pension Trust				
Cash and cash equivalents	$ 34	$ 34	$ -	$ -
Equity securities				
U.S.:				
Large-cap	55	-	55	-
Commingled debt	18	-	18	-
International	29	-	29	-
Debt securities:				
U.S. Treasury	27	27	-	-
Corporate	93	-	93	-
Derivatives:				
Total return swaps	1	-	1	-
Total LG&E pension trust assets	$ 257	$ 61	$ 196	$ -

	December 31, 2010			
	Total	Level 1	Level 2	Level 3
LG&E Pension Trust				
Cash and cash equivalents	$ 1	$ 1	$ -	$ -
Equity securities				
U.S.:				
Large-cap	77	-	77	-
Small/Mid-cap	18	-	18	-
Commingled debt	93	-	93	-
International	28	-	28	-
Total LG&E pension trust assets	$ 217	$ 1	$ 216	$ -

The fair value measurements of cash and cash equivalents are based on the amounts on deposit.

The market approach is used to measure fair value of equity securities. The fair value measurements of equity securities (excluding commingled funds), which are generally classified as Level 1, are based on quoted prices in active markets. These securities represent actively and passively managed investments that are managed against various equity indices.

Investments in commingled funds are classified as Level 2 and categorized as equity securities. The fair value measurements are based on firm quotes of net asset values per share, which are not considered obtained from a quoted price in an active market. For the PPL Services Corporation Master Trust for 2011 and 2010 and the

LG&E pension trust for 2011, these securities represent investments that are measured against the Russell 1000 Growth Index, the Russell 3000 Index and the MSCI EAFE Index. For the LG&E pension trust during 2010, these securities represent passively and actively managed investments in equity funds managed against the S&P 500 Index, the Russell 2500 Growth & Value Indexes and the MSCI EAFE Index.

The fair value measurements of debt securities are generally based on evaluated prices that reflect observable market information, such as actual trade information for identical securities or for similar securities, adjusted for observable differences. Debt securities are generally measured using a market approach, including the use of matrix pricing. Common inputs include reported trades; broker/dealer bid/ask prices, benchmark securities and credit valuation adjustments. When necessary, the fair value of debt securities is measured using the income approach, which incorporates similar observable inputs as well as benchmark yields, credit valuation adjustments, reference data from market research publications, monthly payment data, collateral performance and new issue data. During 2010 and the first ten months of 2011 for the LG&E pension trust, debt securities within commingled trusts were managed against the Barclays Aggregated Bond Index and the Barclays U.S. Government/Credit Long Index. During the last two months of 2011, the debt securities for the LG&E pension trust were transitioned to debt securities similar to those within the PPL Services Corporation Master Trust. The debt securities, excluding those in commingled funds, held by the PPL Services Corporation Master Trust at December 31, 2011 have a weighted-average coupon of 3.96% and a weighted-average maturity of 25 years.

The fair value measurements of derivative instruments 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. These securities represent investments in interest rate swaps. Interest rate swaps are valued based on the swap details such as: swap curves, notional amount, index and term of index, reset frequency and payer/receiver credit ratings.

There were no assets classified as Level 3.

Expected Cash Flows - Defined Benefit Plan

LG&E's defined benefit plan has the option to utilize available prior year credit balances to meet current and future contribution requirements. However, LG&E contributed $13 million to its pension plan in January 2012.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid by the separate plan trust.

	Pension
2012	$ 15
2013	15
2014	15
2015	15
2016	15
2017-2021	90

Contributions

LG&E made contributions to its defined benefit pension plan of $38 million and $12 million in 2011 and 2010. LG&E also made contributions to the defined benefit pension plan in which is participates of $26 million and $8 million in 2011 and 2010. In 2012, LG&E made contributions of $13 million to its defined benefit pension plan.

LG&E 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. LG&E funded this plan $6 million and $7 million in 2011 and 2010. Continuation of this past practice would cause LG&E to contribute $7 million to the other postretirement benefit plan in 2012.

Savings Plans

Substantially all of LG&E'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
$ 5	$ 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, LG&E 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	37.00%	$ 64	$ 4	$ 1
E.W. Brown Units 6-7	38.00%	39	3	-
Trimble County Units 5-6	29.00%	31	1	-
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00%	44	2	5
Trimble County Unit 1	75.00%	297	19	11
Trimble County Unit 2	14.25%	190	7	7
December 31, 2010				
Generating Plants				
Trimble County Units 7-10	37.00%	$ 63	$ 1	$ 1
E.W. Brown Units 6-7	38.00%	39	2	1
Trimble County Units 5-6	29.00%	26	-	2
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00%	44	-	4
Trimble County Unit 1	75.00%	288	9	17
Trimble County Unit 2	14.25%	2	-	187

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

LG&E 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 approval in August 2011. Pursuant to the OVEC power purchase contract, LG&E 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. LG&E's proportionate share of OVEC's outstanding debt was $81 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	$	20
2013		21
2014		21
2015		21
2016		22
Thereafter		595
	$	700

In addition, LG&E 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
$ 22	$ 4	$ 17

LG&E 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. LG&E also enters into contracts for other coal related consumables, coal transportation and fleeting services, which expire at different time periods through 2018. LG&E also has transportation contracts for natural gas that extend through 2018.

Legal Matters

LG&E is involved in legal proceedings, claims and litigation in the ordinary course of business. LG&E cannot predict the outcome of such matters, or whether such matters may result in material liabilities, unless otherwise noted.

TC2 Construction

In June 2006, LG&E and KU, 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. LG&E 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, LG&E likely will be faced with significant new recordkeeping and reporting requirements. Also, LG&E 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. LG&E will continue to evaluate the provisions of the Dodd-Frank Act. At this time, LG&E 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 LG&E to make wholesale sales of electric power and related products at market-based rates. In those orders, the FERC directed LG&E 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 LG&E. Also, in June 2011, PPL filed its market-based rate update for the Southeast region, including LG&E. In June 2011, the FERC issued an Order approving LG&E'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, LG&E 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.

LG&E 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. LG&E 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 LG&E, 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, LG&E 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.

Air

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, LG&E'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 $1.6 billion for LG&E (which includes $100 million associated with currently approved ECR plans through 2013 to achieve emissions reductions and manage coal combustion residuals, $1.4 billion 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 $100 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 LG&E 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 LG&E'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 LG&E coal-fired generating plants, the stay of the CSAPR will initially only impact the unit dispatch order. With the return of the CAIR and LG&E'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. LG&E'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, LG&E'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. LG&E 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 upgraded or new sulfur dioxide scrubbers at the Mill Creek plant and retirement of the Cane Run plant 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, LG&E 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 $1.6 billion noted under "Air" above. LG&E has also announced the anticipated retirement of coal-fired generating units at the Cane Run plant 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, LG&E is currently assessing whether changes in the final rule warrant revision of its approved compliance plans. LG&E is continuing to conduct in-depth reviews of the MATS.

Regional Haze and Visibility

LG&E submitted analyses of the visibility impacts of its Best Available Retrofit Technology (BART) eligible sources to the Kentucky Division for Air Quality (KDAQ). Only LG&E's Mill Creek plant was determined to have a significant regional haze impact. The KDAQ has submitted a regional haze state implementation plan (SIP) to the EPA which requires the Mill Creek plant to reduce its sulfuric acid mist emissions from Units 3 and 4. After approval of the SIP by the EPA and revision of the Mill Creek plant's Title V air permit, LG&E intends to install sorbent injection controls at the plant to reduce sulfuric acid mist emissions. 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 LG&E 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, LG&E received information requests for its Mill Creek and Trimble County plants, but has received no further communications from the EPA since providing their responses. LG&E cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any.

If LG&E is found to have violated NSR regulations, LG&E 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 LG&E 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, LG&E 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 four of LG&E’s affiliates but excluding LG&E, 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. LG&E cannot predict the outcome of this litigation or estimate a range of reasonably possible losses, if any.

In 2011, LG&E and its jointly owned power plants emitted approximately 21 million tons of carbon dioxide compared with 19 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, LG&E 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. LG&E 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 LG&E 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.

LG&E 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. LG&E 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 LG&E’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. LG&E 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. LG&E 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 LG&E 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. LG&E 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. LG&E 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, LG&E 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. LG&E 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.

<u>Superfund and Other Remediation</u>

LG&E is remediating or has completed the remediation of several sites that were not addressed under a regulatory program such as Superfund, but for which LG&E 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 LG&E. There are additional sites, formerly owned or operated by LG&E predecessors or affiliates, for which LG&E 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 LG&E currently lacks information, the costs of remediation and other liabilities could be substantial. LG&E also could incur other non-remediation costs at sites included in current consent orders or other contaminated sites which could be significant. LG&E 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 LG&E to take more extensive assessment and remedial actions at former coal gas manufacturing facilities. LG&E cannot estimate a range of reasonably possible losses, if any, related to these matters.

From time to time, LG&E 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 LG&E'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 LG&E'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 LG&E.

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. LG&E 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. LG&E 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, LG&E 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, LG&E 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 LG&E'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, LG&E is obligated to pay its share of the excess. The maximum exposure of this obligation cannot be determined at this time.

LG&E 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

LG&E and subsidiaries of LKE and PPL engage in related party transactions. Transactions between LG&E and LKE subsidiaries are eliminated upon consolidation of LKE. Transactions between LG&E 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 regulations.

Wholesale Sales and Purchases

LG&E and KU 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 LG&E 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
$ 190	$ 32	$ 200

In addition, LG&E and KU provide services to each other and to LKS. Billings between LG&E and KU 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 LG&E are reimbursed through LKS.

Intercompany Borrowings

In November 2010, a PPL Energy Supply subsidiary held term notes with LG&E. 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 4.33% and 6.48%. Interest on these notes is included in "Interest Expense with Affiliates." When balances were outstanding, interest on these notes was $1 million for 2010.

LG&E participates in an intercompany money pool agreement whereby LKE and/or KU make available to LG&E 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, $12 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 KU was not significant for 2011 or 2010.

Prior to PPL's acquisition of LKE in November 2010, LG&E had long-term loans from its former E.ON AG affiliates. During 2010, LG&E incurred interest expense on these debt arrangements of $22 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 7 for a discussion regarding capital transactions by LG&E. 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			
Net derivative gains (losses)	$ -	$ -	$ 19
Miscellaneous	-	-	1
Total Other Income	-	-	20
Other Expense			
Charitable contributions	1	-	2
Miscellaneous	1	3	1
Total Other Expense	2	3	3
Other Income (Expense) - net	$ (2)	$ (3)	$ 17

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). LG&E 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	$ 25	$ 25	$ -	$ -
Restricted cash and cash equivalents (a)	29	29	-	-
Total assets	$ 54	$ 54	$ -	$ -
Liabilities				
Price risk management liabilities:				
Interest rate swaps (b)	$ 60	$ -	$ 60	$ -

	December 31, 2010			
	Total	Level 1	Level 2	Level 3
Assets				
Cash and cash equivalents	$ 2	$ 2	$ -	$ -
Short-term investments - municipal debt securities	163	163	-	-
Restricted cash and cash equivalents (a)	22	22	-	-
Total assets	$ 187	$ 187	$ -	$ -
Liabilities				
Price risk management liabilities:				
Energy commodities (c)	$ 2	$ -	$ 2	$ -
Interest rate swaps (b)	34	-	34	-
Total liabilities	$ 36	$ -	$ 36	$ -

(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.
(b) Current portion is included in "Other current liabilities" on the Balance Sheets. The long-term portion is included in "Price risk management liabilities" on the Balance Sheets.
(c) Included in "Other current liabilities" on the Balance Sheets.

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, LG&E 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.

Price Risk Management Assets/Liabilities - Interest Rate Swaps

To manage its interest rate risk, LG&E generally uses interest rate contracts such as forward-starting swaps, floating-to-fixed swaps and fixed-to-floating swaps. LG&E uses an income approach to measure the fair value of these contracts, utilizing readily observable inputs, such as forward interest rates (e.g., LIBOR and government security rates) as well as inputs that may not be observable, such as credit valuation adjustments. In certain cases, LG&E cannot practicably obtain market information to value credit risk and therefore rely on its own models. These models use projected probabilities of default based on historical observances. When the credit valuation adjustment is significant to the overall valuation, the contracts are classified as Level 3.

Financial Instruments Not Recorded at Fair Value

The carrying values and estimated fair values of LG&E’s non-trading financial instruments follow:

	December 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 1,112	$ 1,164	$ 1,112	$ 1,069

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. The carrying value of short-term investments approximates fair value due to the liquid nature and short-term duration of these instruments.

Credit Concentration Associated with Financial Instruments

LG&E 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 LG&E to manage credit risk, including master netting arrangements and collateral requirements.

At December 31, 2011, LG&E's credit exposure was not significant.

15. Derivative Instruments and Hedging Activities

Risk Management Objectives

LG&E 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 LG&E's parent, LKE, (acquired in November 2010) under the risk management policy.

Market Risk

Market risk is the potential loss LG&E may incur as a result of price changes associated with a particular financial or commodity instrument. LG&E utilizes forward contracts and swaps as part of risk management strategies, to minimize unanticipated fluctuations in earnings caused by changes in commodity prices and interest rates. All derivatives are recognized on the Balance Sheets at their fair value, unless they qualify for NPNS.

By definition, the regulatory environment for LG&E significantly mitigates market risk. LG&E's rates are set to permit the recovery of prudently incurred costs, including certain mechanisms for fuel, gas supply and environmental expenses. These mechanisms generally provide for timely recovery of market price and volumetric fluctuations associated with these expenses. LG&E primarily utilized forward financial transactions to manage price risk associated with expected economic generation capacity in excess of expected load requirements.

LG&E also utilizes over-the-counter interest rate swaps to limit exposure to market fluctuations on interest expense.

Credit Risk

Credit risk is the potential loss LG&E may incur due to a counterparty's non-performance, including defaults on payments and energy commodity deliveries.

LG&E is exposed to credit risk from interest rate derivatives with financial institutions.

LG&E's credit risk stems from its commodity derivatives for contracts for energy sales and purchases. In the event a supplier of LG&E defaults on its obligation, LG&E would be required to seek replacement power or replacement fuel in the market. In general, incremental costs incurred by LG&E would be recoverable from customers in future rates.

LG&E 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. LG&E 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

LG&E 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.

LG&E had no obligation to return cash collateral under master netting arrangements at December 31, 2011 and December 31, 2010.

LG&E had posted cash collateral under master netting arrangements of $29 million at December 31, 2011 and $19 million at December 31, 2010.

Commodity Price Risk (Non-trading)

LG&E 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 LG&E at December 31, 2010 was not significant. There is no economic position at December 31, 2011. Unrealized gains (losses) for economic activity for LG&E in 2011 and 2010 were not significant.

Interest Rate Risk

LG&E has issued debt to finance its operations, which exposes it to interest rate risk. LG&E utilizes various financial derivative instruments to adjust the mix of fixed and floating interest rates in its debt portfolio, adjust the duration of its debt portfolio and lock in benchmark interest rates in anticipation of future financing, when appropriate. Risk limits under the risk management program are designed to balance risk exposure to volatility in interest expense and changes in the fair value of LG&E's debt portfolio due to changes in benchmark interest rates.

Economic Activity

LG&E enters into interest rate swap contracts that economically hedge interest payments on variable rate debt. Because realized gains and losses from the swaps, including a terminated swap contract, are recoverable through regulated rates, any subsequent changes in fair value of these derivatives are included in regulatory assets or liabilities until they are realized as interest expense. Realized gains and losses are recognized in "Interest Expense" on the Statements of Income when the hedged transaction occurs. At December 31, 2011, LG&E held contracts with aggregate notional amounts of $179 million that range in maturity through 2033. The fair value of these contracts was recorded as liabilities of $60 million and $34 million at December 31, 2011 and 2010, with equal offsetting amounts recorded as regulatory assets.

Prior to the third quarter of 2010, LG&E accounted for these contracts as cash flow hedges and reclassified amounts previously recorded in AOCI to earnings in the same period during which the forecasted transaction affected earnings.

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, except for the changes in fair value of LG&E's interest rate swaps, which beginning in the third quarter of 2010, have been recognized as regulatory assets. See Note 4 for amounts recorded in regulatory assets at December 31, 2011 and December 31, 2010.

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 Decembere 31, 2011 and 2010. The following table presents the fair value and location of derivative instruments not designated as hedging instruments recorded on the Balance Sheets:

	December 31, 2011		December 31, 2010	
	Derivatives not designated as hedging instruments		Derivatives not designated as hedging instruments	
	Assets	**Liabilities**	**Assets**	**Liabilities**
Current:				
Other Current Assets/Liabilities (a):				
Interest rate swaps	$ -	$ 5	$ -	$ 2
Commodity contracts	-	-	-	2
Total current	-	5	-	4
Noncurrent:				
Price Risk Management Assets/Liabilities (a):				
Interest rate swaps	-	55	-	32
Total noncurrent	-	55	-	32
Total derivatives	$ -	$ 60	$ -	$ 36

(a) Represents the location on the Balance Sheet.

The following tables present the pre-tax effect of derivative instruments recognized in income or regulatory assets for the periods ended December 31, 2011 and 2010, for the Successor and Predecessor.

		Successor	
Derivatives Not Designated as Hedging Instruments	**Location of Gain (Loss) Recognized in Income on Derivatives**	**Year Ended December 31, 2011**	**Two Months Ended December 31, 2010**
Interest rate swaps	Interest expense	$ (8)	$ (1)
Commodity contracts	Operating revenues - retail and wholesale	(1)	(2)
	Total	$ (9)	$ (3)

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Predecessor Ten Months Ended October 31, 2010
Interest rate swaps	Interest expense	$ (7)
Commodity contracts	Operating revenues - retail and wholesale	3
	Total	$ (4)

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	December 31, 2011	December 31, 2010
Interest rate swaps	Regulatory assets	$ (26)	$ (43)

Credit Risk-Related Contingent Features

Certain of LG&E's derivative contracts contain credit risk-related contingent provisions which, when in a net liability position, would permit the counterparties to require the transfer of additional collateral upon a decrease in the credit ratings of LG&E. Most of these provisions would require LG&E to transfer additional collateral or permit the counterparty to terminate the contract if the applicable credit rating were to fall below investment grade. Some of these provisions also would 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 the applicable credit rating were to fall below investment grade (i.e., below BBB- for S&P or Fitch, 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 LG&E on derivative instruments in net liability positions.

Additionally, certain of LG&E's derivative contracts contain credit risk-related contingent provisions that require LG&E to provide "adequate assurance" of performance if the other party has reasonable grounds for insecurity regarding LG&E'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. This would typically involve negotiations among the parties. However, amounts disclosed below represent assumed immediate payment or immediate and ongoing full collateralization for derivative instruments in net liability positions with "adequate assurance" provisions.

At December 31, 2011, the effect of a decrease in credit ratings below investment grade on derivative contracts that contain credit contingent features and were in a net liability position is summarized as follows:

Aggregate fair value of derivative instruments in a net liability position with credit risk-related contingent provisions	$	39
Aggregate fair value of collateral posted on these derivative instruments		29
Aggregate fair value of additional collateral requirements in the event of a credit downgrade below investment grade (a)		10

(a) Includes the effect of net receivables and payables already recorded on the Balance Sheet.

16. Goodwill and Other Intangible Assets

Goodwill

As a result of the November 1, 2010 acquisition by PPL, LG&E recognized $389 million of goodwill. The allocation of goodwill was based on LG&E'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)	$ 124	$ 46	$ 124	$ 6
Land and transmission rights (b)	6	1	6	-
Emission allowances (c)	2	-	7	-
OVEC power purchase agreement (d)	87	6	87	1
Total subject to amortization	$ 219	$ 53	$ 224	$ 7

(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 $5 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 no regulatory offset	$ 1	$ -
Intangible assets with regulatory offset	45	7
Total	$ 46	$ 7

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	$ 22	$ 25	$ 23	$ 24	$ 14

17. Asset Retirement Obligations

LG&E's AROs are primarily related to the final retirement of assets associated with generating units, natural gas mains and wells. LG&E'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 LG&E 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	$	31
Accretion expense		2
Changes in estimated cash flow or settlement date		30
Obligations settled		(1)
ARO at October 31, 2010, Predecessor		62
Purchase accounting		(13)
ARO at December 31, 2010, Successor		49
Accretion expense		3
Obligations incurred		2
Changes in estimated cash flow or settlement date		4
Obligations settled		(1)
ARO at December 31, 2011, Successor	$	57

The classification of AROs on the Balance Sheets was as follows.

	December 31, 2011		December 31, 2010	
Current portion (a)	$	2	$	-
Long-term portion (b)		55		49
Total	$	57	$	49

(a) Included in "Other current liabilities."
(b) Included in "Asset retirement obligations."

18. Available-for-Sale Securities

LG&E classifies certain short-term investments as available-for-sale. Available-for-sale securities are carried on the Balance Sheet at fair value. Unrealized gains and losses on these securities are reported, net of tax, in OCI or are recognized currently in earnings when a decline in fair value is determined to be other-than-temporary. The specific identification method is used to calculate realized gains and losses.

LG&E had no available-for-sale securities at December 31, 2011. At December 31, 2010, LG&E held $163 million in municipal debt securities classified as available-for-sale securities at both amortized cost and fair value.

There were no securities with credit losses at December 31, 2011 and 2010.

Short-term Investments

At December 31, 2010, LG&E held $163 million aggregate principal amount of tax-exempt revenue bonds issued by Louisville/Jefferson County, Kentucky on behalf of LG&E that were purchased from the remarketing agent in 2008. At December 31, 2010, these investments were reflected in "Short-term investments" on the Balance Sheet. In 2011, LG&E received $163 million for its investments in these bonds when they were remarketed to unaffiliated investors. No realized or unrealized gains (losses) were recorded on these securities, as the difference between carrying value and fair value was not significant.

19. New Accounting Guidance Pending Adoption

Fair Value Measurements

Effective January 1, 2012, LG&E 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 LG&E.

Testing Goodwill for Impairment

Effective January 1, 2012, LG&E 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 LG&E.

Improving Disclosures about Offsetting Balance Sheet Items

Effective January 1, 2013, LG&E 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 LG&E.

20. 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	$ 20	$ 53
Interest on borrowed money	30	11
Interest to affiliated companies on borrowed money	-	29
Other cash paid for interest	9	10

21. Notes to Statement of Income for the Year

See page 115, line 6, column (g). Electric Utility Depreciation Expense includes $9 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 6, column (i). Gas Utility Depreciation Expense $4 million applicable to Common Utility Plant apportioned to Gas Operations.

See page 115, line 8, column (g). Electric Utility Amortization and Depletion of Utility Plant includes $6 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 8, column (i). Gas Utility Amortization and Depletion of Utility Plant includes $2 million applicable to Common Utility Plant apportioned to Gas Operations.

Name of Respondent Louisville Gas and Electric 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

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				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

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	(10,454,766)		(10,454,766)		
2	10,454,766		10,454,766		
3					
4	10,454,766		10,454,766	127,761,995	138,216,761
5					
6					
7					
8					
9				124,352,697	124,352,697
10					

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Schedule Page: 122(a)(b) Line No.: 5 Column: f

Beginning in the third quarter of 2010, the Accumulated Other Comprehensive Income (219) balance was reclassified to Regulatory Assets (182), Long-Term Interest Rate Swaps.

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)	4,547,589,659	3,626,363,496
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	131,640,892	105,721,872
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	4,679,230,551	3,732,085,368
9	Leased to Others		
10	Held for Future Use	649,014	649,014
11	Construction Work in Progress	215,276,377	152,710,828
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	4,895,155,942	3,885,445,210
14	Accum Prov for Depr, Amort, & Depl	2,117,873,453	1,783,822,898
15	Net Utility Plant (13 less 14)	2,777,282,489	2,101,622,312
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,097,801,848	1,783,822,898
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	20,071,605	
22	Total In Service (18 thru 21)	2,117,873,453	1,783,822,898
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)	2,117,873,453	1,783,822,898

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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
703,277,916				217,948,247	3
					4
					5
21,103,199				4,815,821	6
					7
724,381,115				222,764,068	8
					9
					10
47,481,610				15,083,939	11
					12
771,862,725				237,848,007	13
236,679,884				97,370,671	14
535,182,841				140,477,336	15
					16
					17
236,679,884				77,299,066	18
					19
					20
				20,071,605	21
236,679,884				97,370,671	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
236,679,884				97,370,671	33

Name of Respondent Louisville Gas and Electric 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	2,240	
3	(302) Franchises and Consents	100	
4	(303) Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	2,340	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	6,293,327	
9	(311) Structures and Improvements	292,984,744	30,938,544
10	(312) Boiler Plant Equipment	1,243,463,710	163,599,265
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	192,667,700	24,441,013
13	(315) Accessory Electric Equipment	168,644,172	10,062,030
14	(316) Misc. Power Plant Equipment	14,421,154	1,990,042
15	(317) Asset Retirement Costs for Steam Production	27,801,470	4,692,057
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,946,276,277	235,722,951
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	6	
28	(331) Structures and Improvements	4,776,156	187,220
29	(332) Reservoirs, Dams, and Waterways	11,461,159	384,657
30	(333) Water Wheels, Turbines, and Generators	19,602,376	398,411
31	(334) Accessory Electric Equipment	5,413,702	114,887
32	(335) Misc. Power PLant Equipment	310,301	
33	(336) Roads, Railroads, and Bridges	29,931	
34	(337) Asset Retirement Costs for Hydraulic Production	103,529	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	41,697,160	1,085,175
36	D. Other Production Plant		
37	(340) Land and Land Rights	8,133	
38	(341) Structures and Improvements	14,896,367	108,073
39	(342) Fuel Holders, Products, and Accessories	7,350,941	342,967
40	(343) Prime Movers	152,055,190	6,282,083
41	(344) Generators	33,223,315	-4,941
42	(345) Accessory Electric Equipment	19,840,185	860,870
43	(346) Misc. Power Plant Equipment	3,794,109	3,355
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	231,168,240	7,592,407
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,219,141,677	244,400,533

Name of Respondent Louisville Gas and Electric 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) (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
			2,240		2
100					3
					4
100			2,240		5
					6
					7
			6,293,327		8
4,196,980		3,010,481	322,736,789		9
17,737,600		-2,985,191	1,386,340,184		10
					11
3,093,989		4,145,218	218,159,942		12
639,406		12,050	178,078,846		13
66,012			16,345,184		14
732,205	-3,924,626	-38,429	27,798,267		15
26,466,192	-3,924,626	4,144,129	2,155,752,539		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			6		27
			4,963,376		28
155,564			11,690,252		29
55,574			19,945,213		30
18,753			5,509,836		31
54			310,247		32
			29,931		33
			103,529		34
229,945			42,552,390		35
					36
			8,133		37
			15,004,440		38
95,084			7,598,824		39
864,933			157,472,340		40
46,427			33,171,947		41
8,552			20,692,503		42
1,141			3,796,323		43
		38,429	38,429		44
1,016,137		38,429	237,782,939		45
27,712,274	-3,924,626	4,182,558	2,436,087,868		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	9,354,461	
49	(352) Structures and Improvements	6,184,990	318,718
50	(353) Station Equipment	121,334,837	7,378,683
51	(354) Towers and Fixtures	39,984,865	85,651
52	(355) Poles and Fixtures	51,809,718	1,748,552
53	(356) Overhead Conductors and Devices	46,557,043	850,942
54	(357) Underground Conduit	2,437,094	
55	(358) Underground Conductors and Devices	5,111,200	557,090
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	13,761	238,693
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	282,787,969	11,178,329
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	3,363,450	747,400
61	(361) Structures and Improvements	3,862,755	362,163
62	(362) Station Equipment	94,329,037	12,456,596
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	129,765,231	7,316,382
65	(365) Overhead Conductors and Devices	222,246,594	11,953,226
66	(366) Underground Conduit	68,835,840	705,716
67	(367) Underground Conductors and Devices	134,637,571	11,129,020
68	(368) Line Transformers	134,212,872	6,222,476
69	(369) Services	27,138,029	181,714
70	(370) Meters	37,274,312	401,679
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	82,686,877	3,987,785
74	(374) Asset Retirement Costs for Distribution Plant	481,205	145,334
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	938,833,773	55,609,491
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		
87	(390) Structures and Improvements		
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment	9,648,242	971,760
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	4,318,905	419,440
92	(395) Laboratory Equipment		
93	(396) Power Operated Equipment	2,605,232	31,396
94	(397) Communication Equipment		
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	16,572,379	1,422,596
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)	16,572,379	1,422,596
100	TOTAL (Accounts 101 and 106)	3,457,338,138	312,610,949
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	3,457,338,138	312,610,949

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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
			9,354,461		48
		-47,153	6,456,555		49
1,148,921			127,564,599		50
21			40,070,495		51
276,058			53,282,212		52
165,679			47,242,306		53
			2,437,094		54
8,492			5,659,798		55
					56
			252,454		57
1,599,171		-47,153	292,319,974		58
					59
			4,110,850		60
14,411		47,153	4,257,660		61
517,602			106,268,031		62
					63
1,601,286		2,132	135,482,459		64
185,026		-2,132	234,012,662		65
9,214		-3,978	69,528,364		66
299,028		3,978	145,471,541		67
89,118			140,346,230		68
51,545			27,268,198		69
20,203			37,655,788		70
					71
					72
3,977,573			82,697,089		73
			626,539		74
6,765,006		47,153	987,725,411		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
					86
					87
					88
1,893,016		64,613	8,791,599		89
					90
134,421			4,603,924		91
					92
113,094		30,818	2,554,352		93
					94
					95
2,140,531		95,431	15,949,875		96
					97
					98
2,140,531		95,431	15,949,875		99
38,217,082	-3,924,626	4,277,989	3,732,085,368		100
					101
					102
					103
38,217,082	-3,924,626	4,277,989	3,732,085,368		104

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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.: 104 Column: e

Reversal of Asset Retirement Obligation (ARO) costs that do not qualify for ARO status.	$	(638,407)
Partial reversal of AROs associated with Trimble County joint use assets which are jointly owned by LG&E and KU. A corresponding ARO was recorded on KU which represents KU's ownership of the joint use assets.		(3,286,219)
Total Adjustments	$	(3,924,626)

Schedule Page: 204 Line No.: 104 Column: f

Balance includes $95,431 related to the transfer of assets among electric, gas and common. It also includes $4,182,558 for transfer of Trimble County Unit 2 ("TC2") hyperbolic cooling tower 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
Louisville Gas and Electric 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	Seven Tracts in or near Louisville, Kentucky	Various	Various	384,311
3	US 42: Tract No. D152	01/31/2000	2015-2020	253,321
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Site Development - Kentucky Street Substation D61	06/30/1992	2016-2021	11,382
23				
24				
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46				
47	Total			649,014

Name of Respondent Louisville Gas and Electric 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

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	MILL CREEK LIMESTONE GRINDING UPGRADE	8,322,419
3	MC2 FGD REFURBISHMENT	6,000,941
4	GENERATOR STATOR BAR STUDY- LGE	3,761,826
5	MC3 BURNERS	2,541,943
6	TC CCP LANDFILL PH1 RAVINE - LGE	2,463,612
7	CANE RUN - NEW LANDFILL	2,379,235
8	TC2 CAPITAL SPARES - LGE	2,237,425
9	MC2 CONDENSER TUBING	1,888,772
10	TC1 BOILER SUPERHEATER PENDANT	1,853,908
11	TC1 BOILER REAR REHEATER REPLACEMENT	1,596,633
12	TC1 CATALYST LAYER INSTALLATION	1,550,054
13	TC AIR HEATER BASKET REPLACEMENT	1,469,953
14	TC CCP HOLCIM BARGE-LGE	1,105,397
15	STEAM PRODUCTION MINOR	16,954,848
16		
17	HYDRAULIC POWER MAJOR	
18	OHIO FALLS REDEVELOPMENT UNIT #5	14,486,776
19	OHIO FALLS REDEVELOPMENT UNIT #3	3,607,323
20	OHIO FALLS REDEVELOPMENT UNIT #4	3,467,302
21	OHIO FALLS REDEVELOPMENT UNIT #1	3,458,835
22	OHIO FALLS REDEVELOPMENT UNIT #2	3,458,105
23	OHIO FALLS REDEVELOPMENT UNIT #8	3,331,080
24	HYDRAULIC POWER MINOR	394,633
25		
26	OTHER PRODUCTION MAJOR	
27	PR13 TURBINE BLADE VANE REPLACEMENT - LGE	4,145,002
28	TC CT HOT GAS PATH INSPECTION LGE#3	1,470,813
29	ENVIRONMENTAL COMPLIANCE STUDY-AIR-LGE	1,351,539
30	NEXT BASELOAD UNIT NGCC CR	1,081,834
31	OTHER PRODUCTION MINOR	1,313,627
32		
33	TRANSMISSION MAJOR	
34	MIDDLETOWN - COLLINS 138kV LINE	3,449,335
35	MIDDLETOWN SUB 345kV BREAKER INSTALLATION	2,131,561
36	TRANSMISSION TOWER RELOCATION	2,064,835
37	BREAKER REPLACEMENT	1,512,292
38	TRANSMISSION MINOR	5,701,581
39		
40	DISTRIBUTION MAJOR	
41	OLD HENRY SUBSTATION	4,589,768
42	JEFFERSONTOWN CIRCUIT WORK	3,456,253
43	TOTAL	152,710,828

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	OLD HENRY CIRCUIT WORK	2,245,745
2	TIP TOP (FT. KNOX) RECONDUCTOR	2,134,640
3	WORTHINGTON SUBSTATION EXPANSION	2,114,955
4	JEFFERSONTOWN SUB EXPANSION	2,047,406
5	GENERAL RELIABILITY - LG&E	1,797,822
6	HARRODS CREEK SUBSTATION	1,670,603
7	LG&E POLE REPLACEMENT	1,547,093
8	LG&E MAJOR STORM	1,153,436
9	DISTRIBUTION MINOR	19,399,668
10		
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42		
43	TOTAL	152,710,828

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	1,720,718,237	1,718,516,694	2,201,543	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	109,526,670	109,526,670		
4	(403.1) Depreciation Expense for Asset Retirement Costs	2,060,683	2,060,683		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	213,175	213,175		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-71,751	-71,751		
9	Fuel Stock	222,875	222,875		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	111,951,652	111,951,652		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	37,484,777	37,484,777		
13	Cost of Removal	12,448,616	12,448,616		
14	Salvage (Credit)	543,374	543,374		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	49,390,019	49,390,019		
16	Other Debit or Cr. Items (Describe, details in footnote):	1,275,233	1,275,233		
17	Other		2,201,543	-2,201,543	
18	Book Cost or Asset Retirement Costs Retired	-732,205	-732,205		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,783,822,898	1,783,822,898		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,139,976,387	1,139,976,387		
21	Nuclear Production				
22	Hydraulic Production-Conventional	8,935,663	8,935,663		
23	Hydraulic Production-Pumped Storage				
24	Other Production	70,023,001	70,023,001		
25	Transmission	140,205,714	140,205,714		
26	Distribution	413,521,397	413,521,397		
27	Regional Transmission and Market Operation				
28	General	11,160,736	11,160,736		
29	TOTAL (Enter Total of lines 20 thru 28)	1,783,822,898	1,783,822,898		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2011/Q4

FOOTNOTE DATA

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

Reclass cost of removal and salvage on ARO parent assets from Other Regulatory Liabilities (254) to Accumulated Provision for Depreciation (108) for assets which do not qualify as AROs	$ 568,245
Reserve adjustments due to changes in asset retirement cost estimates	(120,737)
Net effect of reserve transfers among electric, gas and common	167,414
Reclass cost of removal and salvage on ARO parent assets from Other Regulatory Liabilities (254) to Accumulated Provision for Depreciation (108) for settlement of AROs	102,803
Customer payments related to construction projects	557,508
Total Other Debit or Credit Items	$ 1,275,233

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
Louisville Gas and Electric 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 Corporation (5.63%)			
2	Common Stock $100 par value, 5,630 shares			
3	700 shares	11/18/52		70,000
4	700 shares	1/8/53		70,000
5	700 shares	2/25/53		70,000
6	700 shares	4/10/53		70,000
7	700 shares	5/12/53		70,000
8	1,400 shares	7/27/53		140,000
9	730 shares	3/4/05		104,286
10				
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13				
14				
15				
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	594,286

Name of Respondent Louisville Gas and Electric 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.
	56,300			1
				2
		70,000		3
		70,000		4
		70,000		5
		70,000		6
		70,000		7
		140,000		8
		104,286		9
				10
				11
				12
				13
				14
				15
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	56,300	594,286		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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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)	68,043,290	52,502,546	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)	26,022,047	27,504,391	Electric
8	Transmission Plant (Estimated)	1,770,755	1,615,760	Electric
9	Distribution Plant (Estimated)	1,534,114	1,505,791	Electric, Gas
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)	29,326,916	30,625,942	
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)	4,943,153	5,596,506	Various
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	102,313,359	88,724,994	

Schedule Page: 227 Line No.: 9 Column: b

	Balance End of Year
Electric	$ 1,488,674
Gas	45,440
Total Distribution	$ 1,534,114

Schedule Page: 227 Line No.: 9 Column: c

	Balance End of Year
Electric	$ 1,456,443
Gas	49,348
Total Distribution	$ 1,505,791

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	183,638.00	2,708	62,379.00	
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	46,818.00	685		
19	Other:				
20	Charges to 143		10		
21	Cost of Sales/Transfers:				
22	Sales to KU	24,072.00	356		
23	Transfer to IMEA/IMPA	1,559.00			
24	Adjustment to final 2010	684.00	10		
25					
26					
27					
28	Total	26,315.00	366		
29	Balance-End of Year	110,505.00	1,647	62,379.00	
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	901.00		901.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	901.00			
40	Balance-End of Year			901.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	901.00	2,432		
45	Gains				
46	Losses				

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.
62,379.00		62,379.00		1,621,854.00		1,992,629.00	2,708	1
								2
								3
				62,379.00		62,379.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						46,818.00	685	18
								19
							10	20
								21
						24,072.00	356	22
						1,559.00		23
						684.00	10	24
								25
								26
								27
						26,315.00	366	28
62,379.00		62,379.00		1,684,233.00		1,981,875.00	1,647	29
								30
								31
								32
								33
								34
								35
901.00		901.00		44,149.00		47,753.00		36
				1,802.00		1,802.00		37
								38
				901.00		1,802.00		39
901.00		901.00		45,050.00		47,753.00		40
								41
								42
								43
				901.00	146	1,802.00	2,578	44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	22,187.00	21	20,345.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Purchases from 3rd Party	1,000.00	76,250		
10	Purchases from KU	1,900.00	864		
11					
12					
13					
14					
15	Total	2,900.00	77,114		
16					
17	Relinquished During Year:				
18	Charges to Account 509	10,786.00	75,359		
19	Other:				
20	Charges to 549/158	12,401.00			
21	Cost of Sales/Transfers:				
22	Transfer to IMEA/IMPA	475.00			
23	Adjustment to final 2010	338.00	911		
24	Removed by EPA			20,345.00	
25					
26					
27					
28	Total	813.00	911	20,345.00	
29	Balance-End of Year	1,087.00	865		
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				

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.
20,345.00		20,345.00				83,222.00	21	1
								2
								3
								4
								5
								6
								7
								8
						1,000.00	76,250	9
						1,900.00	864	10
								11
								12
								13
								14
						2,900.00	77,114	15
								16
								17
						10,786.00	75,359	18
								19
						12,401.00		20
								21
						475.00		22
						338.00	911	23
20,345.00		20,345.00				61,035.00		24
								25
								26
								27
20,345.00		20,345.00				61,848.00	911	28
						1,087.00	865	29
								30
								31
								32
								33
								34
								35
								36
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Schedule Page: 229 Line No.: 24 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.: 24 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.: 24 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.”

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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	ASC 715 - Pension and Postretirement	213,180,670	12,124,492			225,305,162
2	Long-Term Interest Rate Swap	34,281,361	35,186,478	244/245	9,901,375	59,566,464
3	Winter Storm 2009 - Electric (Aug-10 to Jul-20)	41,851,089		571/593	4,367,070	37,484,019
4	Winter Storm 2009 - Gas (Aug-10 to Jul-20)	160,702		880	16,769	143,933
5	Wind Storm 2008 (Aug-10 to Jul-20)	22,559,486		593	2,354,034	20,205,452
6				190/		
7	ASC 740 - Income Taxes		15,035,797	282/283	305,663	14,730,134
8	Asset Retirement Obligation - Electric	6,587,791	4,030,312	108/230	1,194,570	9,423,533
9	Asset Retirement Obligation - Gas	250,046	2,032,870	230	1,048,996	1,233,920
10	Asset Retirement Obligation - Common	1,275	7,832			9,107
11				426.5/427/		
12	Swap Termination (Aug-10 to Apr-35)	9,195,698		930.2	258,476	8,937,222
13	Summer Storm 2011		8,052,145	580	20	8,052,125
14	Coal Contracts (Nov-10 to Dec-15)	9,214,861		253	4,282,428	4,932,433
15	Performance-Based Rates	2,434,953	3,438,719	495/803	1,855,580	4,018,092
16	Fuel Adjustment Clause	3,191,000	5,497,000	440-445	5,090,000	3,598,000
17	Unamortized Debt Expense (various)	3,667,742		181	186,561	3,481,181
18	Gas Supply Clause	1,112,017	4,994,730	254/803	4,423,367	1,683,380
19	MISO Exit Fee (Mar-09 to Feb-14)	1,509,467		575.7	749,834	759,633
20	Corporate Headquarters Lease (Nov-10 to Jul-15)	794,713		253/931	195,193	599,520
21	KY Consortium for Carbon Storage (Aug-10 to Jul-14)	786,578		930.2	219,511	567,067
22	Rate Case Expenses - Electric (Aug-10 to Jul-13)	722,898		928	279,832	443,066
23	Rate Case Expenses - Gas (Aug-10 to Jul-13)	413,700		928	160,142	253,558
24	Rate Case Expenses - Electric (Mar-09 to Feb-12)	289,050		928	247,757	41,293
25	Rate Case Expenses - Gas (Mar-09 to Feb-12)	96,825		928	82,993	13,832
26	EKPC FERC Transmission Costs (Mar-09 to Feb-14)	536,979		456/566	169,572	367,407
27	Carbon Management Research Group (Aug-10 to Jul-20)	154,470	97,560	930.2	97,560	154,470
28	General Management Audit - Electric		90,545			90,545
29	General Management Audit - Gas		29,487			29,487
30	Environmental Cost Recovery	4,720,309	1,046,099	440-445	5,766,408	
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44	TOTAL	357,713,680	91,664,066		43,253,711	406,124,035

Schedule Page: 232 Line No.: 7 Column: c

The regulatory assets represent the future revenue impact from the reversal of deferred income tax liability required for a tax depreciation basis adjustment.

Schedule Page: 232 Line No.: 14 Column: f

The balance in Coal Contracts (Nov-10 to Dec-15) was adjusted due to the purchase of LG&E 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	11,265,929
2011 Amortization of Purchase Accounting Adjustment	(4,282,428)
2010 Amortization of Purchase Accounting Adjustment	(2,051,068)
Total for Coal Contracts (Nov-10 to Dec-15)	$ 4,932,433

Schedule Page: 232 Line No.: 17 Column: f

The balance represents the reclassification from Unamortized Debt Expense (various) due to the purchase of LG&E by PPL in November 2010, as these costs are considered to have no fair value in purchase accounting under US GAAP. However, LG&E 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	3,698,836
2011 Amortization of Purchase Accounting Adjustment	(186,562)
2010 Amortization of Purchase Accounting Adjustment	(31,094)
Rounding	1
Total for Unamortized Debt Expense (various)	$ 3,481,181

Schedule Page: 232 Line No.: 20 Column: f

The balance in Corporate Headquarters Lease (Nov-10 to Jul-15) was adjusted due to the purchase of LG&E 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 Purchase Accounting	$ -
Purchase Accounting Adjustment	794,713
2011 Amortization of Purchase Accounting Adjustment	(195,193)
Total for Corporate Headquarters Lease (Nov-10 to Jul-15)	$ 599,520

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	389,157,352				389,157,352
2						
3	OVEC Power Purchase Contract					
4	(Nov-10 to Mar-26)	85,809,209		254	5,472,941	80,336,268
5						
6	Coal Contracts					
7	(Nov-10 to Dec-16)	117,659,961		254	39,340,574	78,319,387
8						
9	Valuation of SO2 Allowances					
10	(Nov-10 to Dec-40)	3,026,064		254	1,011,877	2,014,187
11						
12	Valuation of NOx Ozone					
13	Allowances (Nov-10 to Dec-11)	226,663		254	226,663	
14						
15	Valuation of NOx Annual					
16	Allowances (Nov-10 to Dec-11)	4,180,673		254	4,180,673	
17						
18	Customer Credit Accounts					
19	Receivable	69,519	804,935	142/193	426,403	448,051
20						
21				181/189/		
22	Financing Expense	166,704	2,101,853	232	2,242,970	25,587
23						
24	Cellular Antenna Billable Chgs	34,666	223,483	143/456	258,149	
25						
26	Land Options	4,138		921	4,138	
27						
28	Rounding	-2	2			
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45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	600,334,947				550,300,832

Schedule Page: 233 Line No.: 1 Column: f

The Goodwill balance of $389,157,352 represents Louisville Gas and Electric Company's franchise value as a result of the acquisition by PPL Corporation in November 2010 which is attributed to the going concern of the business.

Schedule Page: 233 Line No.: 4 Column: f

The balance of $80,336,268 relates to the fair measurement of $86,856,705 for the power purchase contract 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.: 7 Column: f

The balance of $78,319,387 relates to the fair value measurement of $123,813,249 for Louisville Gas and Electric'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.: 10 Column: f

The balance of $2,014,187 relates to the fair value measurement of $3,219,107 for LG&E'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
Louisville Gas and Electric 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	-33,175,309	-33,473,306
3	Other Post Retirement & Employment Benefits	19,964,421	18,083,387
4	Regulatory Tax Adjustments	19,884,276	32,950,000
5	Vacation Pay	1,553,756	1,540,648
6	Asset Retirement Obligation	18,155,786	
7	Other - See Notes for Detail	88,611,568	68,949,149
8	TOTAL Electric (Enter Total of lines 2 thru 7)	114,994,498	88,049,878
9	Gas		
10	Pensions	-8,741,716	-8,825,444
11	Other Post Retirement & Employment Benefits	5,630,272	5,068,404
12	Regulatory Tax Adjustments	1,626,726	1,612,499
13	Vacation Pay	479,322	476,045
14	Asset Retirement Obligation	8,416,754	
15	Other - See Notes for Detail	4,237,996	3,781,063
16	TOTAL Gas (Enter Total of lines 10 thru 15	11,649,354	2,112,567
17	Other (Specify)	563,530	738,222
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	127,207,382	90,900,667

Notes

	Electric Amounts Beg. Bal.	Electric Amounts End. Bal.	Gas Amounts Beg. Bal.	Gas Amounts End. Bal.
Workers' Compensation	$ 611,966	$1,194,749	$ 211,433	$ 357,129
Demand Side Management	222,860	155,059	1,767,924	1,277,775
Contingent Liability	433,016	491,843	-	-
State Tax Adjustment	223,557	(203,639)	(143,367)	(285,766)
Capitalized Gas Inventory	-	-	1,545,083	1,594,807
Other	(824,278)	718,645	338,514	355,015
	----------	----------	----------	----------
Total Line 7/15 without Purchase Accounting	667,121	2,356,657	3,719,587	3,298,960
Purchase Accounting Adjustments (PAA):				
PAA – pollution control bonds	2,033,883	2,033,883	524,460	524,460
Amortization of PAA – pollution control bonds				
2011	-	(92,842)	-	(23,940)
2010	(15,474)	(15,474)	(3,990)	(3,990)
PAA – power purchase contract	33,787,258	33,787,258		
Amortization of PAA - power purchase contract				
2011	-	(2,128,974)	-	-
2010	(407,476)	(407,476)	-	-
PAA – interest rate swaps	797,450	797,450	-	-
Amortization of PAA - interest rate swaps				
2010	(797,450)	(797,450)	-	-
PAA – emission allowances	3,251,929	3,251,929	-	-
Amortization of PAA - emission allowances				
2011	-	(2,108,074)	-	-
2010	(360,336)	(360,336)	-	-
PAA – regulatory liabiiity for coal supply contracts	48,163,354	48,163,354	-	-
Amortization of PAA - reg. liab. for coal supply contracts				
2011	-	(15,303,484)	-	-
2010	(2,393,629)	(2,393,629)	-	-
PAA – coal supply contracts	4,382,446	4,382,446	-	-
Amortization of PAA – coal supply contracts				
2011	-	(1,665,864)	-	-
2010	(797,865)	(797,865)	-	-
PAA – rent commitment	309,143	309,143	-	-

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.

Amortization of PAA – rent commitment				
2011	-	(52,717)	-	(12,366)
2010	(8,786)	(8,786)	(2,061)	(2,061)
	-----------	-----------	----------	----------
Total Line 7/15 with Purchase Accounting	$88,611,568	$68,949,149	$4,237,996	$3,781,063
	===========	===========	==========	==========

	Other Amounts Beginning	Other Amounts Ending
FAS 87 Pensions - BTL	$ (292,262)	$ -
Mark to Market	663,744	546,174
Non-Qualified Thrift	192,048	192,048
	-----------	-----------
Line 17	$ 563,530	$ 738,222
	===========	===========

Balance Beginning of Year	$127,207,382
Less Debits to:	
Acct 410.1	63,598,208
Acct 410.2	139,696
Plus Credits to:	
Acct 411.1	14,060,570
Acct 411.2	314,388
Other Balance Sheet Accounts	13,056,231

Balance at End of Year	$ 90,900,667
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	75,000,000		
3	Total Common	75,000,000		
4				
5	Preferred Stock			
6	Preferred Stock, $25 Par Value	1,720,000		
7	Preferred Stock, Without Par Value	6,750,000		
8	Total Preferred	8,470,000		
9				
10				
11	Note:			
12	There is no Call Price for Common Stock,			
13	Without Par Value			
14				
15				
16	The Common Stock of Louisville Gas and Electric			
17	Company is owned by its parent company,			
18	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
Louisville Gas and Electric 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
21,294,223	425,170,424					2
21,294,223	425,170,424					3
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Schedule Page: 250 Line No.: 8 Column: a

No shares of preferred stock remain issued or outstanding.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	Account 211:	
2	Contributed Capital - Misc.	1,277,667,368
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40	TOTAL	1,277,667,368

Schedule Page: 253 Line No.: 2 Column: b

The balance in Other Paid-in Capital (208-211) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value, the balance was adjusted for the fixed rate pollution control bonds net of deferred taxes and goodwill. The balance also includes elimination of Retained Earnings (215, 215.1, 216) at October 31, 2010. See footnotes for 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	$ 83,581,499
Purchase Accounting Adjustment - goodwill	389,157,352
Purchase Accounting Adjustment - fixed rate pollution control bonds	(4,018,374)
Purchase Accounting Adjustment - prior retained earnings	808,946,891
Total for Other Paid-in Capital (208-211)	$ 1,277,667,368

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

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	835,889
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22	TOTAL	835,889

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	Jefferson County 2000 Series A, due 05/01/2027, Variable	25,000,000	883,831
4	Trimble County 2000 Series A, due 08/01/2030, Variable	83,335,000	1,154,826
5	Jefferson County 2001 Series A, due 09/01/2027, Variable	10,104,000	526,085
6	Jefferson County 2001 Series A, due 09/01/2026, Variable	22,500,000	242,653
7	Trimble County 2001 Series A, due 09/01/2026, Variable	27,500,000	263,855
8	Jefferson County 2001 Series B, due 11/01/2027, Variable	35,000,000	281,244
9	Trimble County 2001 Series B, due 11/01/2027, Variable	35,000,000	281,283
10	Trimble County 2002 Series A, due 10/01/2032, Variable	41,665,000	1,112,006
11	Louisville Metro 2003 Series A, due 10/01/2033, 1.900%	128,000,000	4,037,495
12	Louisville Metro 2005 Series A, due 02/01/2035, 5.750%	40,000,000	1,428,142
13	Trimble County 2007 Series A, due 06/01/2033, 4.600%	60,000,000	1,239,280
14	Louisville Metro 2007 Series A, due 06/01/2033, 5.625%	31,000,000	938,023
15	Louisville Metro 2007 Series B, due 06/01/2033, 1.900%	35,200,000	814,429
16	Interest Rate Swaps (3)		
17			
18	First Mortgage Bonds: (4)		
19	2010 due 11/15/2015, 1.625%	250,000,000	2,563,689
20			882,500 D
21	2010 due 11/15/2040, 5.125%	285,000,000	3,570,026
22			3,100,800 D
23	TOTAL ACCOUNT 221	1,109,304,000	23,320,167
24			
25	ACCOUNT 222 (5):		
26	Reacquired Pollution Control Bonds:		
27	Louisville Metro 2003 Series A, due 10/01/2033, Variable	-128,000,000	
28	Louisville Metro 2007 Series B, due 06/01/2033, Variable	-35,200,000	
29	TOTAL ACCOUNT 222	-163,200,000	
30			
31	ACCOUNT 223:		
32	TOTAL ACCOUNT 223		
33	TOTAL	952,680,717	23,320,167

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	05/01/2027	05/19/2000	05/01/2027	25,000,000	1,249,667	3
08/01/2000	08/01/2030	08/01/2000	08/01/2030	83,335,000	190,872	4
09/11/2001	09/01/2027	09/11/2001	09/01/2027	10,104,000	19,063	5
03/06/2002	09/01/2026	03/06/2002	09/01/2026	22,500,000	166,740	6
03/06/2002	09/01/2026	03/06/2002	09/01/2026	27,500,000	98,533	7
03/22/2002	11/01/2027	03/22/2002	11/01/2027	35,000,000	272,312	8
03/22/2002	11/01/2027	03/22/2002	11/01/2027	35,000,000	270,890	9
10/15/2002	10/01/2032	10/15/2002	10/01/2032	41,665,000	112,135	10
11/20/2003	10/01/2033	11/20/2003	10/01/2033	128,000,000	2,364,820	11
04/13/2005	02/01/2035	04/13/2005	02/01/2035	40,000,000	2,300,000	12
04/26/2007	06/01/2033	04/26/2007	06/01/2033	60,000,000	2,760,000	13
04/26/2007	06/01/2033	04/26/2007	06/01/2033	31,000,000	1,743,750	14
04/26/2007	06/01/2033	04/26/2007	06/01/2033	35,200,000	652,820	15
					7,772,722	16
						17
						18
11/16/2010	11/15/2015	11/16/2010	11/15/2015	250,000,000	4,062,500	19
		11/16/2010	11/15/2015			20
11/16/2010	11/15/2040	11/16/2010	11/15/2040	285,000,000	14,606,250	21
		11/16/2010	11/15/2040			22
				1,109,304,000	38,643,074	23
						24
						25
						26
11/20/2003	10/01/2033	11/20/2003	10/01/2033		-13,887	27
04/26/2007	06/01/2033	04/26/2007	06/01/2033		-4,456	28
					-18,343	29
						30
						31
						32
				1,115,530,470	38,324,519	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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			
2	Account 224 (6):		
3	Purchase Accounting Adjustments for Fair Value Measurement		
4	Louisville Metro 2007 Series A, due 06/01/2033, 5.625%	2,702,070	
5	Trimble County 2007 Series A, due 06/01/2033, 4.600%	-2,062,667	
6	Jefferson County 2000 Series A, due 05/01/2027, 5.375%	1,397,125	
7	Louisville Metro 2005 Series A, due 02/01/2035, 5.750%	4,540,189	
8	TOTAL ACCOUNT 224	6,576,717	
9			
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23			
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25			
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27			
28			
29			
30			
31			
32			
33	TOTAL	952,680,717	23,320,167

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
						3
		11/1/2010	6/1/2033	2,562,479	-119,649	4
		11/1/2010	6/1/2033	-1,956,108	91,336	5
		11/1/2010	5/1/2027	1,298,338	-84,675	6
		11/1/2010	2/1/2035	4,321,761	-187,224	7
				6,226,470	-300,212	8
						9
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						32
				1,115,530,470	38,324,519	33

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 Louisville Gas and Electric Company (LG&E) issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates LG&E 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) As of December 31, 2011, the company had in effect four interest-rate swap agreements to hedge its exposure to tax exempt rates related to Pollution Control Bonds, Variable Rate Series. The Company’s positions under the swap agreements are to pay a fixed rate and receive a variable rate based on the Bond Market Association Municipal Swap Index or London Interbank Offered Rate (LIBOR). The specifics for each swap agreement related to notional amounts, maturity dates, payable and receivable positions are as follows:

Notional Amount	Maturity	Payable	Receivable
$83,335,000	11/01/2020	Fixed 5.495%	BMA Index
$32,000,000	10/01/2033	Fixed 3.657%	68% of 1 mo LIBOR
$32,000,000	10/01/2033	Fixed 3.645%	68% of 1 mo LIBOR
$32,000,000	10/01/2033	Fixed 3.695%	68% of 1 mo LIBOR

(4) In November 2010, LG&E requested and was granted, authorization to issue first mortgage bonds totaling $535 million by the Kentucky Public Service Commission in its September 30, 2010, Order in Case No. 2010-00205. 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, LG&E 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.

(5) As of December 31, 2011, LG&E had no remaining repurchased bonds.

(6) 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 estimated 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
Louisville Metro 2007 Series A, due 6/1/2033, 5.625%	$31,000,000	$4,540,189	$35,540,189
Trimble County 2007 Series A, due 6/1/2033, 4.600%	$60,000,000	($2,062,667)	$57,937,333
Jefferson County 2000 Series A, due 5/1/2027, 5.375%	$25,000,000	$2,702,070	$27,702,070
Louisville Metro 2005 Series A, due 2/1/2035, 5.750%	$40,000,000	$1,397,125	$41,397,125

The purchase accounting adjustments were recorded to Other Long-Term Debt Account (224) and are being amortized over the lives of the related issues to Interest on Long-Term Debt Account (427).

Schedule Page: 256 Line No.: 1 Column: i

Interest on Bonds and Revolving Credit: (221/222/224/231):	
Total Account (221)	$ 38,643,074
Total Account (222)	(18,343)
Total Account (224)	(300,212)
Interest on Long-Term Debt	38,324,519
Notes Payable (231)	185,005
Total Interest on Long-Term Debt (427)	$ 38,509,524
Interest on Advances to Associated Companies (223):	
Advances to Associated Companies (223)	$ -
Other Short Term Interest	9,663
Total Account (430)	$ 9,663

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)	124,352,697
2		
3		
4	Taxable Income Not Reported on Books	
5	See footnote	8,639,746
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See footnote	88,605,441
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See footnote	11,752,453
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See footnote	161,807,268
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	48,038,163
28	Show Computation of Tax:	
29		
30	Federal Tax Net Income	48,038,163
31	35% Rounded	16,813,357
32	Add: Adjustment of Prior Years' Taxes to Actual & Other	-5,339,655
33		
34	Total:	11,473,702
35		
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41		
42		
43		
44		

Schedule Page: 261 Line No.: 5 Column: b

Environmental Cost Recovery	$ 5,039,496
Contributions In Aid Of Construction	3,600,250

Total	$ 8,639,746
	===========

Schedule Page: 261 Line No.: 10 Column: b

Federal Income Taxes:	
Utility Operating Income	$11,962,850
Other Income and Deductions	(489,148)
Provision for Deferred Income Taxes	54,166,643
MISO Exit Fees-Transmission	1,030,463
Capitalized Interest	6,606,874
Loss on Reacquired Debt, Net of Amortization	970,787
Workers' Compensation	1,570,093
Asset Retirement Obligations	2,109,576
Regulatory Expenses	770,723
Prepaid Insurance	1,652,429
Storm Damages	6,737,872
Other	1,488,394

Total Without Purchase Accounting	88,577,556
Purchase Accounting Adjustments:	
FMV Leases	27,885

Total	$88,605,441
	===========

Schedule Page: 261 Line No.: 15 Column: b

Amortization of Investment Tax Credit	$ 2,805,732
Customer Advances for Construction	1,215,871
Purchased Gas Adjustment	5,919,805
Fuel Adjustment Clause KY	407,000
Mark-to-Market	1,404,045

Total	$11,752,453
	===========

Schedule Page: 261 Line No.: 20 Column: b

Method Life Depreciation	$128,406,173
Cost of Removal	11,881,355
Demand Side Management	1,415,758
Post Retirement Benefits	6,168,959
Summer Storm Damages	8,052,125
IRC 199 Manufacturing Deduction	2,299,901
Bad Debts Reserves	509,141
Contingent Liability	756,814
Current State Income Taxes	1,627,412
Other	389,418

Total Without Purchase Accounting	161,507,056
Purchase Accounting Adjustments:	
FMV Bonds	300,212

Total	$161,807,268
	============

Name of Respondent Louisville Gas and Electric 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

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	-3,741,320		14,303,728	10,562,408	
3	FICA	590,647		6,396,768	6,461,380	
4						
5	Kentucky and Other States:					
6	Income	229,109		9,573,551	9,802,660	
7	Public Service Commission		966,581	1,943,900	1,954,639	
8	Use (Kentucky)	1,088,858		4,804,649	5,221,713	
9	Use (Indiana)			29,808	29,808	
10	Vehicle License			87,826	87,826	
11						
12	Federal & Kentucky:					
13	Unemployment Insurance	54,387		141,297	142,355	
14						
15	Local:					
16	Occupational					
17						
18	Kentucky & Indiana:					
19	Property Taxes	11,376,472		18,302,701	17,645,481	
20						
21	Federal, State & Local					
22	Miscellaneous			35	35	
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	9,598,153	966,581	55,584,263	51,908,305	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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
		27,439,817			-13,136,089	2
526,035		6,370,094			26,674	3
						4
						5
		9,971,422			-397,871	6
	977,320	1,426,854			517,046	7
671,794					4,804,649	8
					29,808	9
					87,826	10
						11
						12
53,329		162,499			-21,202	13
						14
						15
		37,061			-37,061	16
						17
						18
12,033,692		13,613,677			4,689,024	19
						20
						21
					35	22
						23
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						40
13,284,850	977,320	59,021,424			-3,437,161	41

BLANK

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2011/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 1 Column: a

Segregation of Other	Column L Other	Page 115 Gas Acct. 408.1 - 409.1	Page 117 Other Inc & Deductions 408.2 – 409.2	Other Accounts
Federal:				
Income	$(13,136,089)	$(15,476,967)	$(489,148)	$2,830,026
FICA	26,674	1,440,098		(1,413,424)
Kentucky:				
Income	(397,871)	(1,705,889)	(90,284)	1,398,302
PSC	517,046	517,046		0
6% Use (Kentucky)	4,804,649			4,804,649
7% Use (Indiana)	29,808			29,808
Vehicle License	87,826			87,826
Federal & Kentucky:				
Unemployment Ins	(21,202)	35,645		(56,847)
Local:				
Occupational	(37,061)	9,256		(46,317)
Kentucky & Indiana:				
Property Taxes	4,689,024	4,509,354	3,168	176,502
Federal, State & Local:				
Miscellaneous	35			35
Total	$(3,437,161)	$(10,671,457)	$(576,264)	$7,810,560

Reconciliation to page 114-115, line 14-16:

Federal Income:		State Income:		Other:	
Electric	$27,439,817	Electric	$9,971,422	Elec Total	$59,021,424
Gas	(15,476,967)	Gas	(1,705,889)	Gas Total	(10,671,457)
Total	$11,962,850	Total	$8,265,533	Less Federal	(11,962,850)
				Less State	(8,265,533)
				Total	$28,121,584

Schedule Page: 262 Line No.: 2 Column: g

End of the Year balance of $2,830,026 was reclassified to Accounts Receivable (143).

Schedule Page: 262 Line No.: 6 Column: g

End of the Year balance of $1,398,303 was reclassified to Accounts Receivable (143).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6		21,083,051			411.4	2,056,946	
7	15%	23,750,000			411.4	613,466	
8	TOTAL	44,833,051				2,670,412	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16	Gas Utility	691,525			411.4	135,320	
17	TOTAL	691,525				135,320	
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
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36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47		45,524,576				2,805,732	
48	Grand Total	45,524,576				2,805,732	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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
19,026,105	32 years		6
23,136,534	37 years		7
42,162,639			8
			9
			10
			11
			12
			13
			14
			15
556,205	33 years		16
556,205			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
42,718,844			47
42,718,844			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	Valuation of Coal Contracts					
2	(Nov-10 to Dec-15)	9,214,861	182.3	4,282,428		4,932,433
3						
4	Brown CT Long-Term Service					
5	Agreement	4,460,129	232/107	722,458	92,951	3,830,622
6						
7	Corporate Headquarters Lease					
8	(Nov-10 to Jul-15)	766,828	182.3	167,308		599,520
9						
10	Prepaid Transmission System Fee:					
11	MCI Telecom	631,668	454	36,796		594,872
12						
13	Deferred Compensation	493,696			33,542	527,238
14						
15	CSX Transmission Line					
16	Construction		107	273,304	368,000	94,696
17						
18	Unearned Revenue	45,764				45,764
19	Pole Attachments					
20						
21	Clearing Accounts Transferred	45,813	184	30,385,875	30,367,238	27,176
22	from Other Deferred Debits					
23						
24						
25						
26						
27						
28						
29						
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38						
39						
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41						
42						
43						
44						
45						
46						
47	TOTAL	15,658,759		35,868,169	30,861,731	10,652,321

Schedule Page: 269 Line No.: 2 Column: f

The balance of $4,932,433 relates to the fair value measurement of $11,262,929 for the Louisville Gas and Electric 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 $599,520 relates to the revaluation of $794,713 for Louisville Gas and Electric Company's rent commitment for the Corporte 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.

Schedule Page: 269 Line No.: 16 Column: f

In 2011, CSX Corporation requested Louisville Gas and Electric Company move transmission lines and related equipment on CSX property.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	358,504,863	108,250,773	118,293,380
3	Gas	64,465,864	48,078,985	19,035,813
4				
5	TOTAL (Enter Total of lines 2 thru 4)	422,970,727	156,329,758	137,329,193
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	422,970,727	156,329,758	137,329,193
10	Classification of TOTAL			
11	Federal Income Tax	362,343,439	128,518,249	106,311,257
12	State Income Tax	60,627,288	27,811,509	31,017,936
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		254	38,283,384	254/190	47,798,780	357,977,652	2
		254	11,969,418	254	11,900,463	93,440,081	3
							4
			50,252,802		59,699,243	451,417,733	5
							6
							7
							8
			50,252,802		59,699,243	451,417,733	9
							10
			33,368,853		40,703,628	391,885,206	11
			16,883,949		18,995,615	59,532,527	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Loss on Reacquired Debt	7,748,933	17,104	333,941
4	Storm Damages	25,120,944	4,203,456	3,685,689
5	FAC Under Recovery	1,241,300	1,503,567	1,345,244
6	Asset Retirement Obligation	11,499,258	620,784	12,120,042
7	Prepaid Insurance	1,381,170	28,625	558,873
8	Other	73,279,114	18,121,154	24,223,588
9	TOTAL Electric (Total of lines 3 thru 8)	120,270,719	24,494,690	42,267,377
10	Gas			
11	Loss on Reacquired Debt	783,647	3,282	64,082
12	Storm Damages	-2,718	352	6,875
13	Asset Retirement Obligation	1,813,486	97,900	1,911,386
14	Purchased Gas	-2,231,635	4,911,133	2,608,330
15	Prepaid Insurance	323,979	6,715	131,093
16	Other	-3,177,146	3,575,951	297,748
17	TOTAL Gas (Total of lines 11 thru 16)	-2,490,387	8,595,333	5,019,514
18	Other	3,577,127		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	121,357,459	33,090,023	47,286,891
20	Classification of TOTAL			
21	Federal Income Tax	102,639,085	28,590,216	40,597,336
22	State Income Tax	18,718,374	4,499,807	6,689,555
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

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
						7,432,096	3
						25,638,711	4
						1,399,623	5
							6
						850,922	7
				182/283	9,307,149	76,483,829	8
					9,307,149	111,805,181	9
							10
						722,847	11
						-9,241	12
							13
						71,168	14
						199,601	15
						101,057	16
						1,085,432	17
2,180,471	2,180,471	283	3,577,127				18
2,180,471	2,180,471		3,577,127		9,307,149	112,890,613	19
							20
1,876,925	1,876,925		3,025,385		7,871,599	95,478,179	21
303,546	303,546		551,742		1,435,550	17,412,434	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 LG&E by PPL Corporation in November 2010. The following reflects the balance at December 31, 2010:

Beginning Balance:	
MISO Exit Fees	$ 452,539
Rate Case Expenses	393,647
Tax Gain on Sale of Equipment	(13,502,956)
Other	1,060

Accumulated Deferred Income Taxes- Other (283) Without Purchase Accounting	(12,655,710)
Purchase Accounting Adjustments:	
Purchase Accounting Adjustment – power purchase contract	33,787,258
Amortization of Purchase Accounting Adjustment – power purchase contract	(407,476)
Purchase Accounting Adjustment – emission allowances	3,251,929
Amortization of Purchase Accounting Adjustment – emission allowances	(360,336)
Purchase Accounting Adjustment – coal supply contracts	48,163,354
Amortization of Purchase Accounting Adjustment – coal supply contracts	(2,393,629)
Purchase Accounting Adjustment – regulatory asset for coal supply contracts	4,382,446
Amortization of Purchase Accounting Adjustment – regulatory asset for coal supply contracts	(797,865)
Purchase Accounting Adjustment – rent commitment	309,143
Purchase Accounting Adjustment - interest rate swap	797,450
Amortization of Purchase Accounting Adjustment – interest rate swap	(797,450)

Total for Accumulated Deferred Income Taxes- Other (283)	$73,279,114

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 LG&E by PPL in November 2010. The following reflects the activity during the year charged to 410.1:

Debit Change Account 410.1:	
Management Audit Fees	$ 37,124
MISO Exit Fees	21,640
Rate Case Expenses	216,911
Tax Gain on Sale of Equipment	16,691,907
Swap Termination	5,428
Other	6

Total Without Purchase Accounting	16,973,016
Purchase Accounting Adjustment:	
Amortization - power purchase contract	114,932
Amortization - emission allowances	113,803
Amortization - coal supply contracts	826,152
Amortization - regulatory asset for coal supply contracts	89,931
Amortization - rent commitment	3,320

Total	$18,121,154

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 LG&E by PPL in November 2010. The following reflects the activity during the year charged to 411.1:

Credit Change Account 411.1:	
Management Audit Fees	$ 1,901
MISO Exit Fees	422,490
Rate Case Expenses	422,143
Tax Gain on Sale of Equipment	854,951
Swap Termination	105,976
Other	90

Total Without Purchase Accounting	1,807,551
Purchase Accounting Adjustment:	
Amortization - power purchase contract	2,243,906
Amortization - emission allowances	2,221,877
Amortization - coal supply contracts	16,129,636
Amortization - regulatory asset for coal supply contracts	1,755,795
Amortization - rent commitment	64,823

Total	$24,223,588

Schedule Page: 276 Line No.: 8 Column: j

Regulatory Tax Adjustments	$ 5,730,022
Swap Termination	3,577,127

Total	$ 9,307,149

Schedule Page: 276 Line No.: 8 Column: k

The balance in Accumulated Deferred Income Taxes- Other (283) was adjusted due to the purchase of LG&E by PPL Corporation in November 2010. The following reflects the balance at December 31, 2011:

Ending Balance:	
Management Audit Fees	$ 35,223
MISO Exit Fees	51,689
Rate Case Expenses	188,415
Tax Gain on Sale of Equipment	2,334,000
Regulatory Tax Adjustments	5,730,022
Swap Termination	3,476,579
Other	976

Accumulated Deferred Income Taxes- Other (283) Without Purchase Accounting	11,816,904
Purchase Accounting Adjustments:	
Purchase Accounting Adjustment – power purchase contract	33,787,258
2011 Amortization of Purchase Accounting Adjustment – power purchase contract	(2,128,974)
2010 Amortization of Purchase Accounting Adjustment – power purchase contract	(407,476)
Purchase Accounting Adjustment – emission allowances	3,251,929
2011 Amortization of Purchase Accounting Adjustment – emission allowances	(2,108,074)
2010 Amortization of Purchase Accounting Adjustment – emission allowances	(360,336)
Purchase Accounting Adjustment – coal supply contracts	48,163,354
2011 Amortization of Purchase Accounting Adjustment – coal supply contracts	(15,303,484)
2010 Amortization of Purchase Accounting Adjustment – coal supply contracts	(2,393,629)
Purchase Accounting Adjustment – regulatory asset for coal supply contracts	4,382,446

2011 Amortization of Purchase Accounting Adjustment – regulatory asset for coal supply contracts	(1,665,864)
2010 Amortization of Purchase Accounting Adjustment – regulatory asset for coal supply contracts	(797,865)
Purchase Accounting Adjustment – rent commitment	309,143
2011 Amortization of Purchase Accounting Adjustment – rent commitment	(61,503)
Purchase Accounting Adjustment - interest rate swap	797,450
2010 Amortization of Purchase Accounting Adjustment – interest rate swap	(797,450)

Total for Accumulated Deferred Income Taxes- Other (283	$76,483,829

Schedule Page: 276 Line No.: 16 Column: b

Beginning Balance:	
Rate Case Expenses	$ 198,592
Tax Gain on Sale of Equipment	(3,375,738)

Total	$(3,177,146)

Schedule Page: 276 Line No.: 16 Column: c

The balance was adjusted due to the amortization of purchase accounting adjustments that arose from the purchase of LG&E by PPL in November 2010. The following reflects the activity during the year charged to 410.1:

Debit Change Account 410.1:	
Management Audit Fees	$ 12,089
Rate Case Expenses	5,106
Tax Gain on Sale of Equipment	3,557,977

Total Without Purchase Accounting	3,575,172
Purchase Accounting Adjustment:	
Amortization - rent commitment	779

Total	$ 3,575,951

Schedule Page: 276 Line No.: 16 Column: d

The balance was adjusted due to the amortization of purchase accounting adjustments that arose from the purchase of LG&E by PPL in November 2010. The following reflects the activity during the year charged to 411.1:

Credit Change Account 411.1:	
Management Audit Fees	$ 619
Rate Case Expenses	99,684
Tax Gain on Sale of Equipment	182,239

Total Without Purchase Accounting	282,542
Purchase Accounting Adjustment:	
Amortization - rent commitment	15,206

Total	$ 297,748

Schedule Page: 276 Line No.: 16 Column: k

The balance in Accumulated Deferred Income Taxes- Other (283) was adjusted due to the purchase of LG&E by PPL Corporation in November 2010. The following reflects the balance at December 31, 2011:

Ending Balance:	
Management Audit Fees	$ 11,470
Rate Case Expenses	104,014

Accumulated Deferred Income Taxes- Other	

(283) Without Purchase Accounting	115,484
Purchase Accounting Adjustments:	
2011 Amortization of Purchase Accounting Adjustment – rent commitment	(14,427)

Total for Accumulated Deferred Income Taxes- Other (283)	$ 101,057

Schedule Page: 276 Line No.: 18 Column: b

Beginning Balance:	
Swap Termination	$ 3,577,127

Schedule Page: 276 Line No.: 18 Column: e

Debit Change Account 410.2:	
Swap Termination	$ 2,180,471

Schedule Page: 276 Line No.: 18 Column: f

Credit Change Account 411.2:	
Swap Termination	$ 2,180,471

Schedule Page: 276 Line No.: 18 Column: h

Swap Termination	$ 3,577,127

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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	OVEC Power Purchase Contract (Nov-10 to Mar-26)	85,809,209	186	5,472,941		80,336,268
2	Coal Contracts (Nov-10 to Dec-16)	117,659,961	186	39,340,574		78,319,387
3	ASC 740 - Income Taxes	33,521,842	190/282	1,890,695	14,500,596	46,131,743
4	Gas Supply Clause	9,053,548	182.3/495/803	8,064,392	4,050,828	5,039,984
5	DSM Cost Recovery	5,099,134	440-489	6,165,946	4,750,187	3,683,375
6	Asset Retirement Obligation - Gas	2,387,519	108	258,005	19,894	2,149,408
7	Emission Allowances (Nov-10 to Dec-40)	7,433,400	186	5,419,213		2,014,187
8	MISO Exit Fee Refund	346,129			280,629	626,758
9	Purchased Gas Adjustment	230,271	495/803	325,178	573,439	478,532
10	Environmental Cost Recovery		440-445	543,222	862,409	319,187
11	Asset Retirement Obligation - Electric	787,905	108	672,302	73,006	188,609
12						
13						
14						
15						
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41	TOTAL	262,328,918		68,152,468	25,110,988	219,287,438

Schedule Page: 278 Line No.: 1 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 LG&E and Ohio Valley Electric Corporation recognized due to the purchase of LG&E 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		86,856,705
2011 Amortization of Purchase Accounting Adjustment		(5,472,941)
2010 Amortization of Purchase Accounting Adjustment		(1,047,496)
Total for OVEC Power Purchase Contract (Nov-10 to Mar-26)	$	80,336,268

Schedule Page: 278 Line No.: 2 Column: f

The balance in Coal Contracts (Nov-10 to Dec-16) relates to the regulatory offset for the fair value measurement of LG&E's coal contracts recognized due to the purchase of LG&E 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		123,813,249
2011 Amortization of Purchase Accounting Adjustment		(39,340,574)
2010 Amortization of Purchase Accounting Adjustment		(6,153,288)
Total for Coal Contracts (Nov-10 to Dec-16)	$	78,319,387

Schedule Page: 278 Line No.: 3 Column: f

The regulatory liabilities represent the future revenue impact from the reversal of deferred income taxes required for unamortized investment tax credits and deferred taxes provided at rates in excess of currently enacted rates.

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 LG&E's emission allowances recognized due to the purchase of LG&E 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		8,359,713
2011 Amortization of Purchase Accounting Adjustment		(5,419,213)
2010 Amortization of Purchase Accounting Adjustment		(926,313)
Total for Emission Allowances (Nov-10 to Dec-40)	$	2,014,187

Name of Respondent Louisville Gas and Electric 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 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	366,263,255	366,497,652
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	300,002,319	280,877,226
5	Large (or Ind.) (See Instr. 4)	145,251,812	140,028,633
6	(444) Public Street and Highway Lighting	7,235,355	7,041,069
7	(445) Other Sales to Public Authorities	84,489,065	80,391,397
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	903,241,806	874,835,977
11	(447) Sales for Resale	140,077,382	124,859,006
12	TOTAL Sales of Electricity	1,043,319,188	999,694,983
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	1,043,319,188	999,694,983
15	Other Operating Revenues		
16	(450) Forfeited Discounts	5,670,215	6,445,070
17	(451) Miscellaneous Service Revenues	1,562,779	1,457,361
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	2,791,701	2,696,832
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	785,636	1,093,245
22	(456.1) Revenues from Transmission of Electricity of Others	5,620,784	4,224,076
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	16,431,115	15,916,584
27	TOTAL Electric Operating Revenues	1,059,750,303	1,015,611,567

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

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
4,260,122	4,591,882	347,834	349,049	2
				3
3,708,744	3,793,243	41,529	42,292	4
2,430,194	2,602,852	409	433	5
51,351	54,325	335	69	6
1,190,643	1,295,935	3,956	4,025	7
				8
				9
11,641,054	12,338,237	394,063	395,868	10
5,185,682	5,244,942	18	17	11
16,826,736	17,583,179	394,081	395,885	12
				13
16,826,736	17,583,179	394,081	395,885	14

Line 12, column (b) includes $ -10,872,462 of unbilled revenues.
Line 12, column (d) includes -142,044 MWH relating to unbilled revenues

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Schedule Page: 300 Line No.: 4 Column: b

Small (or Comm.) category includes Small and Large Commercial accounts.

Small Commercial and Industrial Sales	$ 137,198,908
Large Commercial Sales	162,803,411
Total Small (or Commercial)	$ 300,002,319

Schedule Page: 300 Line No.: 4 Column: d

Small (or Comm.) category includes Small and Large Commercial accounts.

Small Commercial and Industrial Sales	1,420,199
Large Commercial Sales	2,288,545
Total Small (or Commercial)	3,708,744 MWH

Schedule Page: 300 Line No.: 21 Column: b

Items which compose Other Electric Revenues (456) year-to-date activity:

2011 invoices to Kosmos Cement Co.	$ 502,122
Other items less than $250,000 each	283,514
Total Other Electric Revenues	$ 785,636

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	$ 1,889,333
2011 invoices to Owensboro Municipal Utilities	1,725,887
2011 invoices to City of Frankfort	473,383
2011 invoices to Kentucky Municipal Power Agency	273,251
Other items less than $250,000 each	1,258,930
Total Other Electric Revenues	$ 5,620,784

Schedule Page: 300 Line No.: 1 Column: $

This value contains unbilled revenue of ($8,003,000) and accrued revenue of $(2,869,462). The accrued revenue represents the following:

Fuel Adjustment Clause Accrual	$	407,000
Demand Side Management Accrual		1,763,034
Environmental Cost Recovery Accrual		(5,039,496)
Total Accrual	$	(2,869,462)

Schedule Page: 300 Line No.: 1 Column: MWH

Unbilled revenue of (142,044) MWH represents the net change of unbilled MWH from the previous period, and as a result could be positive or negative.

Name of Respondent Louisville Gas and Electric 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 440					
2	Residential Service (RS)	4,310,696	369,914,708	350,400	12,302	0.0858
3	Volunteer Fire Department (VFD)	381	30,001	1	381,000	0.0787
4	General Service (GS)	297	31,053	234	1,269	0.1046
5	Power Service (PS)	452	29,913	1	452,000	0.0662
6	Commercial Time-of-Day (CTOD)	188	87,576	1	188,000	0.4658
7	Lighting Service (LS)	5,631	1,095,600	6,316	892	0.1946
8	Duplicate Customers			-9,119		
9						
10	Reclassifications and Adjustments	-194	-110,893			0.5716
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38	Subtotal	4,317,451	371,077,958	347,834	12,412	0.0859
39	Unbilled	-57,329	-4,814,703			0.0840
40	Total	4,260,122	366,263,255	347,834	12,248	0.0860
41	TOTAL Billed	11,783,098	914,114,268	394,063	29,902	0.0776
42	Total Unbilled Rev.(See Instr. 6)	-142,044	-10,872,462	0	0	0.0765
43	TOTAL	11,641,054	903,241,806	394,063	29,541	0.0776

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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.
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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 (RS)	83	6,825	159	522	0.0822
3	General Service (GS)	1,328,621	125,594,992	39,775	33,403	0.0945
4	General Responsive Pricing (GRP)	129	13,174	5	25,800	0.1021
5	Power Service (PS)	2,266,888	167,427,377	2,638	859,321	0.0739
6	Commercial Time-of-Day (CTOD)	529,181	35,023,259	99	5,345,263	0.0662
7	Industrial Time-of-Day (ITOD)	1,614,166	91,804,004	73	22,111,863	0.0569
8	Lighting Energy Service (LE)	7	418	5	1,400	0.0597
9	Lighting Service (LS)	49,342	8,739,124	10,312	4,785	0.1771
10	Retail Transmission Service (RTS)	399,440	20,658,119	5	79,888,000	0.0517
11	Duplicate Customers			-11,133		
12						
13	Reclassifications and Adjustments	264	-178,334			-0.6755
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38	Subtotal	6,188,121	449,088,958	41,938	147,554	0.0726
39	Unbilled	-49,183	-3,834,827			0.0780
40	Total	6,138,938	445,254,131	41,938	146,381	0.0725
41	TOTAL Billed	11,783,098	914,114,268	394,063	29,902	0.0776
42	Total Unbilled Rev.(See Instr. 6)	-142,044	-10,872,462	0	0	0.0765
43	TOTAL	11,641,054	903,241,806	394,063	29,541	0.0776

Name of Respondent Louisville Gas and Electric 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 444					
2	General Service (GS)	16	1,750	41	390	0.1094
3	Lighting Energy Service (LE)	2,388	139,474	26	91,846	0.0584
4	Traffic Energy Service (TE)	2,218	187,012	18	123,222	0.0843
5	Lighting Service (LS)	48,235	7,110,701	960	50,245	0.1474
6	Duplicate Customers			-710		
7						
8	Reclassifications and Adjustments	58	-13,046			-0.2249
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38	Subtotal	52,915	7,425,891	335	157,955	0.1403
39	Unbilled	-1,564	-190,536			0.1218
40	Total	51,351	7,235,355	335	153,287	0.1409
41	TOTAL Billed	11,783,098	914,114,268	394,063	29,902	0.0776
42	Total Unbilled Rev.(See Instr. 6)	-142,044	-10,872,462	0	0	0.0765
43	TOTAL	11,641,054	903,241,806	394,063	29,541	0.0776

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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.
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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 (RS)	528	49,453	312	1,692	0.0937
3	General Service (GS)	123,348	11,227,972	2,066	59,704	0.0910
4	Power Service (PS)	339,729	28,321,743	308	1,103,016	0.0834
5	Commercial Time-of-Day (CTOD)	262,312	17,332,380	20	13,115,600	0.0661
6	Special Contracts	297,964	16,208,486	3	99,321,333	0.0544
7	Retail Transmission Service (RTS)	96,642	6,700,952	6	16,107,000	0.0693
8	Industrial Time-of-Day (ITOD)	99,260	6,125,931	13	7,635,385	0.0617
9	Traffic Energy Service (TE)	873	68,346	871	1,002	0.0783
10	Lighting Energy Service (LE)	1,331	77,485	115	11,574	0.0582
11	Lighting Service (LS)	1,736	409,415	2,149	808	0.2358
12	Duplicate Customers			-1,907		
13						
14	Reclassifications and Adjustments	887	-701			-0.0008
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38	Subtotal	1,224,610	86,521,462	3,956	309,558	0.0707
39	Unbilled	-33,967	-2,032,397			0.0598
40	Total	1,190,643	84,489,065	3,956	300,971	0.0710
41	TOTAL Billed	11,783,098	914,114,268	394,063	29,902	0.0776
42	Total Unbilled Rev.(See Instr. 6)	-142,044	-10,872,462	0	0	0.0765
43	TOTAL	11,641,054	903,241,806	394,063	29,541	0.0776

Schedule Page: 304 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $12,148,086.

Schedule Page: 304 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $1,048.

Schedule Page: 304 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $759.

Schedule Page: 304 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $1,234.

Schedule Page: 304 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $323.

Schedule Page: 304 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $14,635.

Schedule Page: 304 Line No.: 8 Column: a
Average number of customers served under this rate schedule is 9,119 - included in revenue class subtotal. These are deducted on line 8 to avoid duplication.

Schedule Page: 304 Line No.: 10 Column: a
Reclassification between FERC accounts and net billing adjustments for prior periods.

Schedule Page: 304.1 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $250.

Schedule Page: 304.1 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $3,661,551.

Schedule Page: 304.1 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $369.

Schedule Page: 304.1 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $6,172,832.

Schedule Page: 304.1 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $1,442,005.

Schedule Page: 304.1 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $4,325,997.

Schedule Page: 304.1 Line No.: 8 Column: c
Includes Fuel Adjustment Clause of $19.

Schedule Page: 304.1 Line No.: 9 Column: c
Includes Fuel Adjustment Clause of $128,041.

Schedule Page: 304.1 Line No.: 10 Column: c
Includes Fuel Adjustment Clause of $1,107,462.

Schedule Page: 304.1 Line No.: 11 Column: a
Average number of customers served under this rate schedule is 11,133 - included in revenue class subtotal. These are deducted on line 11 to avoid duplication.

Schedule Page: 304.1 Line No.: 13 Column: a
Reclassification between FERC accounts and net billing adjustments for prior periods.

Schedule Page: 304.2 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $40.

Schedule Page: 304.2 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $6,202.

Schedule Page: 304.2 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $5,854.

Schedule Page: 304.2 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $125,382.

Schedule Page: 304.2 Line No.: 6 Column: a
Average number of customers served under this rate schedule is 710 - included in revenue class subtotal. These are deducted on line 6 to avoid duplication.

Schedule Page: 304.2 Line No.: 8 Column: a
Reclassification between FERC accounts and net billing adjustments for prior periods.

Schedule Page: 304.3 Line No.: 2 Column: c

Includes Fuel Adjustment Clause of $1,411.

Schedule Page: 304.3 Line No.: 3 Column: c

Includes Fuel Adjustment Clause of $332,570.

Schedule Page: 304.3 Line No.: 4 Column: c

Includes Fuel Adjustment Clause of $923,338.

Schedule Page: 304.3 Line No.: 5 Column: c

Includes Fuel Adjustment Clause of $705,812.

Schedule Page: 304.3 Line No.: 6 Column: c

Includes Fuel Adjustment Clause of $810,718.

Schedule Page: 304.3 Line No.: 7 Column: c

Includes Fuel Adjustment Clause of $254,519.

Schedule Page: 304.3 Line No.: 8 Column: c

Includes Fuel Adjustment Clause of $258,581.

Schedule Page: 304.3 Line No.: 9 Column: c

Includes Fuel Adjustment Clause of $2,359.

Schedule Page: 304.3 Line No.: 10 Column: c

Includes Fuel Adjustment Clause of $3,398.

Schedule Page: 304.3 Line No.: 11 Column: c

Includes Fuel Adjustment Clause of $4,509.

Schedule Page: 304.3 Line No.: 12 Column: a

Average number of customers served under this rate schedule is 1,907 - included in revenue class subtotal. These are deducted on line 12 to avoid duplication.

Schedule Page: 304.3 Line No.: 14 Column: a

Reclassification between FERC accounts and net billing adjustments for prior periods.

Name of Respondent Louisville Gas and Electric 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	Ameren Energy Marketing Company	OS	(3)			
2	American Electric Power Service Corp.	OS	(2)			
3	Associated Electric Coop Inc.	OS	(3)			
4	Bluegrass Generation Company LLC	OS	(4)			
5	BNP Paribas Energy Trading GP	OS	(3)			
6	Cargill Power Markets, LLC	OS	(3)			
7	Carolina Power and Light Company	OS	(3)			
8	Citigroup Energy Inc.	OS	(3)			
9	Constellation Energy Comm. Group, Inc.	OS	(3)			
10	East Kentucky Power Coop, Inc.	OS	(3)			
11	EDF Trading North America, LLC	OS	(3)			
12	Endure Energy, LLC	OS	(3)			
13	Illinois Municipal Electric Agency	OS	(5)			
14	Illinois Municipal Electric Agency	OS	(3)			
	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
Louisville Gas and Electric 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.
1,142		47,702		47,702	1
39,294		1,474,574		1,474,574	2
978		34,392		34,392	3
176		17,600		17,600	4
736		36,111		36,111	5
51,774		2,012,008		2,012,008	6
3,742		277,127		277,127	7
378		12,920		12,920	8
771		42,461		42,461	9
14,323		577,008		577,008	10
4,831		215,704		215,704	11
15,704		637,725		637,725	12
694		20,008		20,008	13
6,103		612,058		612,058	14
0	0	0	0	0	
5,185,682	0	142,814,442	-2,737,060	140,077,382	
5,185,682	**0**	**142,814,442**	**-2,737,060**	**140,077,382**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES FOR RESALE (Account 447)

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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	Illinois Municipal Electric Agency	AD	(3)			
2	Indiana Municipal Power Agency	OS	(7)			
3	Indiana Municipal Power Agency	OS	(3)			
4	Kentucky Municipal Power Agency	OS	(6)			
5	Kentucky Municipal Power Agency	OS	(6)			
6	Kentucky Utilities Company	SF	(1)			
7	MF Global Holdings Ltd.	OS				
8	Merrill Lynch Commodities, Inc.	OS	(3)			
9	Midwest Independent Transm. System Oper	OS	(3)			
10	Newedge USA LLC	OS				
11	Owensboro Municipal Utilities	OS	(8)			
12	Owensboro Municipal Utilities	OS	(6)			
13	Owensboro Municipal Utilities	OS	(6)			
14	PJM Settlement, Inc.	OS	(3)			
	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
Louisville Gas and Electric 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.
			241	241	1
8,077		339,383		339,383	2
6,805		682,441		682,441	3
3,326		137,613		137,613	4
					5
3,641,187		82,377,392		82,377,392	6
			-2,972,674	-2,972,674	7
2,323		104,414		104,414	8
78,631		3,484,610		3,484,610	9
			235,373	235,373	10
276		10,161		10,161	11
4,598		207,721		207,721	12
					13
1,068,293		40,418,891		40,418,891	14
0	0	0	0	0	
5,185,682	0	142,814,442	-2,737,060	140,077,382	
5,185,682	**0**	**142,814,442**	**-2,737,060**	**140,077,382**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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)	Average Monthly CP Demand (f)
1	PJM Settlement, Inc.	OS	(3)			
2	Rainbow Energy Marketing Corp.	OS	(3)			
3	Tenaska Power Services Company	OS	(3)			
4	Tennessee Valley Authority	OS	(3)			
5	The Energy Authority, Inc.	OS	(3)			
6	Trademark Merchant Energy, LLC	OS	(3)			
7	Union Electric Co. (d/b/a Ameren MO)	OS	(3)			
8	Westar Energy, Inc.	OS	(3)			
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
Louisville Gas and Electric 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.
					1
616		25,503		25,503	2
38,364		1,437,721		1,437,721	3
140,728		5,396,355		5,396,355	4
42,209		1,763,768		1,763,768	5
1,770		102,352		102,352	6
2,397		89,396		89,396	7
5,436		219,323		219,323	8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
5,185,682	0	142,814,442	-2,737,060	140,077,382	
5,185,682	**0**	**142,814,442**	**-2,737,060**	**140,077,382**	

Schedule Page: 310 Line No.: 1 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 1 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.
Schedule Page: 310 Line No.: 2 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 2 Column: c
(2) LGE and KU Joint MBRT Tariff.
Schedule Page: 310 Line No.: 3 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 3 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.
Schedule Page: 310 Line No.: 4 Column: b
Energy Imbalance
Schedule Page: 310 Line No.: 4 Column: c
(4)FERC Electric Tariff, Original No. 2, Service Agreement No. 255.
Schedule Page: 310 Line No.: 5 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 5 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.
Schedule Page: 310 Line No.: 6 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 6 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.
Schedule Page: 310 Line No.: 7 Column: a
d/b/a Progress Energy Carolinas Inc.
Schedule Page: 310 Line No.: 7 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 7 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.
Schedule Page: 310 Line No.: 8 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 8 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.
Schedule Page: 310 Line No.: 9 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 9 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.
Schedule Page: 310 Line No.: 10 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 10 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.
Schedule Page: 310 Line No.: 11 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 11 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.
Schedule Page: 310 Line No.: 12 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 12 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.
Schedule Page: 310 Line No.: 13 Column: b
Cost Based Sale
Schedule Page: 310 Line No.: 13 Column: c
(5) LGE CBR Tariff First Revised Service Agreement No. 3.

Schedule Page: 310 Line No.: 14 Column: b
Energy Imbalance

Schedule Page: 310 Line No.: 14 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.1 Line No.: 1 Column: b
December 2010 true-up of accrual estimate for energy made in 2011.

Schedule Page: 310.1 Line No.: 1 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.1 Line No.: 1 Column: j
December 2010 true-up of accrual estimate for energy made in 2011.

Schedule Page: 310.1 Line No.: 2 Column: b
Cost Based Sale

Schedule Page: 310.1 Line No.: 2 Column: c
(7) LGE CBR Tariff Service Agreement No. 4.

Schedule Page: 310.1 Line No.: 3 Column: b
Energy Imbalance

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
Energy Imbalance

Schedule Page: 310.1 Line No.: 4 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4.

Schedule Page: 310.1 Line No.: 5 Column: b
Energy Imbalance Sale of Test Power

Schedule Page: 310.1 Line No.: 5 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4.

Schedule Page: 310.1 Line No.: 5 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, 1 MWH of test power was assigned to Louisville Gas and Electric Company’s off-system sales to Kentucky Municipal Power Agency that were credited to the capital project (Account 107) and are excluded from this report.

Schedule Page: 310.1 Line No.: 5 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, $51 of test power was assigned to Louisville Gas and Electric Company’s off-system sales to Kentucky Municipal Power Agency that were credited to the capital project (Account 107) and are excluded from this report.

Schedule Page: 310.1 Line No.: 6 Column: a
Louisville Gas and Electric Company and Kentucky Utilities Company are owned by PPL Corporation.

Schedule Page: 310.1 Line No.: 6 Column: c
(1) FERC Rate Schedule No. 1. The Power Supply System Agreement, FERC Docket No. ER98-111-000.

Schedule Page: 310.1 Line No.: 7 Column: b
Financial Swap

Schedule Page: 310.1 Line No.: 7 Column: j
Financial swap loss from unfavorable market conditions.

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
Financial Swap

Schedule Page: 310.1 Line No.: 11 Column: b
Cost Based Sale

Schedule Page: 310.1 Line No.: 11 Column: c
(8) LGE CBR Tariff.

Schedule Page: 310.1 Line No.: 12 Column: b
Energy Imbalance

Schedule Page: 310.1 Line No.: 12 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4.

Schedule Page: 310.1 Line No.: 13 Column: b
Energy Imbalance Sale of Test Power

Schedule Page: 310.1 Line No.: 13 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4.

Schedule Page: 310.1 Line No.: 13 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, 7 MWHs of test power was assigned to Louisville Gas and Electric 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: 310.1 Line No.: 13 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, $400 of test power was assigned to Louisville Gas and Electric 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: 310.1 Line No.: 14 Column: b
Market Based Sale

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
Market Based Sale of Test Power

Schedule Page: 310.2 Line No.: 1 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.2 Line No.: 1 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, 2 MWHs of test power was assigned to Louisville Gas and Electric 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.: 1 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, $73 of test power was assigned to Louisville Gas and Electric 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.: 2 Column: b
Market Based Sale

Schedule Page: 310.2 Line No.: 2 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.

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
Market Based Sale

Schedule Page: 310.2 Line No.: 4 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.

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: a
Effective September 6, 2011, Kansas City Energy changed its name to Trademark Merchant Energy, LLC.

Schedule Page: 310.2 Line No.: 6 Column: b
Market Based Sale

Schedule Page: 310.2 Line No.: 6 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.2 Line No.: 7 Column: b
Market Based Sale

Schedule Page: 310.2 Line No.: 7 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff.

Schedule Page: 310.2 Line No.: 8 Column: b
Market Based Sale

Schedule Page: 310.2 Line No.: 8 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
Louisville Gas and Electric 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	2,196,383	2,707,698
5	(501) Fuel	343,602,284	347,218,737
6	(502) Steam Expenses	35,948,091	35,550,622
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.	28,867	1,585,006
9	(505) Electric Expenses	680,461	888,440
10	(506) Miscellaneous Steam Power Expenses	17,323,771	18,192,243
11	(507) Rents	89,098	89,062
12	(509) Allowances	76,950	972
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	399,888,171	403,062,768
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,289,386	3,771,032
16	(511) Maintenance of Structures	2,021,792	2,502,436
17	(512) Maintenance of Boiler Plant	41,319,223	43,512,535
18	(513) Maintenance of Electric Plant	9,416,109	11,307,866
19	(514) Maintenance of Miscellaneous Steam Plant	1,810,437	1,827,795
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	57,856,947	62,921,664
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	457,745,118	465,984,432
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	107,576	106,559
45	(536) Water for Power	38,653	38,682
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses	264,529	177,626
48	(539) Miscellaneous Hydraulic Power Generation Expenses	126,221	89,349
49	(540) Rents	379,818	414,965
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	916,797	827,181
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	12,927	613
54	(542) Maintenance of Structures	370,849	255,666
55	(543) Maintenance of Reservoirs, Dams, and Waterways	74,086	30,978
56	(544) Maintenance of Electric Plant	277,516	352,694
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	735,378	639,951
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	1,652,175	1,467,132

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	43,251	32,537
63	(547) Fuel	17,366,109	21,337,589
64	(548) Generation Expenses	159,275	145,316
65	(549) Miscellaneous Other Power Generation Expenses	35,188	32,000
66	(550) Rents	21,314	19,585
67	TOTAL Operation (Enter Total of lines 62 thru 66)	17,625,137	21,567,027
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	28,319	38,366
70	(552) Maintenance of Structures	100,166	56,450
71	(553) Maintenance of Generating and Electric Plant	1,345,627	3,212,888
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	88,285	344,817
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,562,397	3,652,521
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	19,187,534	25,219,548
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	74,894,547	54,379,719
77	(556) System Control and Load Dispatching	1,588,107	1,626,045
78	(557) Other Expenses	2,164,862	621,822
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	78,647,516	56,627,586
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	557,232,343	549,298,698
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	994,588	785,395
84	(561) Load Dispatching	1,420,983	1,008,551
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	15	111
89	(561.5) Reliability, Planning and Standards Development	412,603	371,678
90	(561.6) Transmission Service Studies	-326	-4,633
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1	8
93	(562) Station Expenses	1,234,462	1,168,692
94	(563) Overhead Lines Expenses	117,265	124,685
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	3,326,104	1,313,486
97	(566) Miscellaneous Transmission Expenses	6,676,094	5,955,824
98	(567) Rents	23,716	23,780
99	TOTAL Operation (Enter Total of lines 83 thru 98)	14,205,505	10,747,577
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	753	-48
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	1,292,533	1,396,985
108	(571) Maintenance of Overhead Lines	1,307,208	773,969
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	17,618	1,032
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,618,112	2,171,938
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	16,823,617	12,919,515

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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)
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	755,046	1,097,996
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	755,046	1,097,996
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)	755,046	1,097,996
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,351,917	1,536,677
135	(581) Load Dispatching	544,332	459,846
136	(582) Station Expenses	1,049,757	964,810
137	(583) Overhead Line Expenses	4,294,787	4,117,195
138	(584) Underground Line Expenses	552,530	666,178
139	(585) Street Lighting and Signal System Expenses	-546	29,321
140	(586) Meter Expenses	6,323,918	6,752,176
141	(587) Customer Installations Expenses	-191,076	-207,245
142	(588) Miscellaneous Expenses	2,998,976	2,905,882
143	(589) Rents	13,434	12,980
144	TOTAL Operation (Enter Total of lines 134 thru 143)	17,938,029	17,237,820
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	290,834	8,407
147	(591) Maintenance of Structures	793,590	718,180
148	(592) Maintenance of Station Equipment	755,932	1,021,695
149	(593) Maintenance of Overhead Lines	19,797,678	11,785,213
150	(594) Maintenance of Underground Lines	1,786,761	1,835,053
151	(595) Maintenance of Line Transformers	234,742	167,572
152	(596) Maintenance of Street Lighting and Signal Systems	456,189	419,180
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant	429,094	270,562
155	TOTAL Maintenance (Total of lines 146 thru 154)	24,544,820	16,225,862
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	42,482,849	33,463,682
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	996,226	945,780
160	(902) Meter Reading Expenses	2,146,609	2,028,527
161	(903) Customer Records and Collection Expenses	5,174,872	5,367,031
162	(904) Uncollectible Accounts	3,578,080	4,474,644
163	(905) Miscellaneous Customer Accounts Expenses	445,330	368,105
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	12,341,117	13,184,087

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	172,016	162,963
168	(908) Customer Assistance Expenses	10,168,761	9,690,833
169	(909) Informational and Instructional Expenses	49,194	54,489
170	(910) Miscellaneous Customer Service and Informational Expenses	270,331	273,700
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	10,660,302	10,181,985
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses	25,095	29,625
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	25,095	29,625
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	16,604,626	16,211,840
182	(921) Office Supplies and Expenses	5,182,222	5,648,387
183	(Less) (922) Administrative Expenses Transferred-Credit	1,971,213	2,050,331
184	(923) Outside Services Employed	4,121,995	4,817,085
185	(924) Property Insurance	4,252,950	4,632,612
186	(925) Injuries and Damages	2,523,088	1,530,489
187	(926) Employee Pensions and Benefits	38,333,662	35,350,404
188	(927) Franchise Requirements	31,420	34,176
189	(928) Regulatory Commission Expenses	1,184,733	973,583
190	(929) (Less) Duplicate Charges-Cr.	123,909	35,336
191	(930.1) General Advertising Expenses	487,584	316,990
192	(930.2) Miscellaneous General Expenses	2,218,134	1,857,526
193	(931) Rents	1,587,843	1,555,884
194	TOTAL Operation (Enter Total of lines 181 thru 193)	74,433,135	70,843,309
195	Maintenance		
196	(935) Maintenance of General Plant	8,917,434	8,546,093
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	83,350,569	79,389,402
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	723,670,938	699,564,990

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Schedule Page: 320 Line No.: 90 Column: b

Credit balance is due to activity for a load flow study related to the new Cane Run Combined Cycle unit.

Schedule Page: 320 Line No.: 90 Column: c

Credit balance is due to adjustments for transmission studies that were performed for and billed to Southwest Power Pool.

Schedule Page: 320 Line No.: 139 Column: b

Credit balance is due to reversal of over-accrued project inspection services invoices from 2010.

Schedule Page: 320 Line No.: 141 Column: b

Credit is due to meter tampering charges billed to customers to offset cost of meter maintenance. Cost is recorded in several other accounts.

Schedule Page: 320 Line No.: 141 Column: c

Credit is due to meter tampering charges billed to customers to offset cost of meter maintenance. Cost is recorded in several other accounts.

Schedule Page: 320 Line No.: 193 Column: b

The balance in Rents (931) was adjusted due to the purchase of LG&E 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	$ 1,565,256
Purchase Accounting Adjustment	22,587
Total for Rents (931)	$ 1,587,843

Schedule Page: 320 Line No.: 193 Column: c

The balance in Rents (931) was adjusted due to the purchase of LG&E 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	$ 1,578,471
Purchase Accounting Adjustment	(22,587)
Total for Rents (931)	$ 1,555,884

Name of Respondent Louisville Gas and Electric 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)
(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	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	Bluegrass Generation Company LLC	OS	(5)	NA	NA	NA
5	Cargill Power Markets, LLC	OS	(1)	NA	NA	NA
6	East Kentucky Power Coop. Inc.	OS	(11)	NA	NA	NA
7	East Kentucky Power Coop. Inc.	OS	(4)	NA	NA	NA
8	EDF Trading North America, LLC	OS	(1)	NA	NA	NA
9	Illinois Municipal Electric Agency	OS	(8)	NA	NA	NA
10	Illinois Municipal Electric Agency	AD	(8)	NA	NA	NA
11	Indiana Municipal Power Agency	OS	(8)	NA	NA	NA
12	Indiana Municipal Power Agency	AD	(8)	NA	NA	NA
13	Indiana Municipal Power Agency	OS	(8)	NA	NA	NA
14	Kentucky Municipal Power Agency	OS	(3)	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		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)	
4,852				245,404		245,404	1
501				22,770		22,770	2
38				1,619		1,619	3
973				59,099		59,099	4
193				8,494		8,494	5
736				31,024		31,024	6
39				3,949		3,949	7
8,960				669,183		669,183	8
466				10,692		10,692	9
8					173	173	10
324				8,021		8,021	11
					-11,070	-11,070	12
471				10,265		10,265	13
1,164				37,490		37,490	14
1,943,401	13,434	79,453	18,439,755	56,494,925	-40,133	74,894,547	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	Kentucky Utilities Company	SF	(2)	NA	NA	NA
2	Ohio Valley Electric Corporation	OS	(6)	NA	NA	NA
3	Ohio Valley Electric Corporation	AD	(6)	NA	NA	NA
4	Owensboro Municipal Utilities	OS	(9)	NA	NA	NA
5	Owensboro Municipal Utilities	OS	(3)	NA	NA	NA
6	PJM Interconnection Association	OS	(1)	NA	NA	NA
7	PJM Interconnection Association	AD	(1)	NA	NA	NA
8	Tennessee Valley Authority	OS	(10)	NA	NA	NA
9	Tennessee Valley Authority	OS	(4)	NA	NA	NA
10	The Energy Authority, Inc.	OS	(7)	NA	NA	NA
11	Union Electric Co. (d/b/a Ameren MO)	OS	(1)	NA	NA	NA
12	Inadvertent Interchange			NA	NA	NA
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	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
(g)	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,120,336				32,401,993		32,401,993	1
783,393			18,439,755	21,895,147		40,334,902	2
					-29,234	-29,234	3
115				2,129		2,129	4
2,846				101,940		101,940	5
15,778				868,442		868,442	6
					-2	-2	7
561				24,801		24,801	8
422				46,661		46,661	9
352				7,457		7,457	10
873				38,345		38,345	11
	13,434	79,453					12
							13
							14
1,943,401	13,434	79,453	18,439,755	56,494,925	-40,133	74,894,547	

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
Energy Imbalance
Schedule Page: 326 Line No.: 4 Column: c
(5) FERC Electric Tariff, Original Volume No. 2, Service Agreement No. 255.
Schedule Page: 326 Line No.: 5 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 5 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 6 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 6 Column: c
(11) EEI Master Power Purchase and Sale Agreeement dated September 14, 2006.
Schedule Page: 326 Line No.: 7 Column: b
Emergency Power
Schedule Page: 326 Line No.: 7 Column: c
(4) TEE Contingency Reserve Sharing Agreement dated November 20, 2009.
Schedule Page: 326 Line No.: 8 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 8 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 9 Column: b
Energy Imbalance
Schedule Page: 326 Line No.: 9 Column: c
(8) Participation Agreement dated February 9, 2004.
Schedule Page: 326 Line No.: 10 Column: b
December 2010 true-up of accrual estimate for energy charges made in 2011.
Schedule Page: 326 Line No.: 10 Column: c
(8) Participation Agreement dated February 9, 2004.
Schedule Page: 326 Line No.: 10 Column: g
December 2010 true-up of accrual estimate for energy charges made in 2011.
Schedule Page: 326 Line No.: 10 Column: l
December 2010 true-up of accrual estimate for energy charges made in 2011.
Schedule Page: 326 Line No.: 11 Column: b
Cost Based Purchase
Schedule Page: 326 Line No.: 11 Column: c
(8) Participation Agreement dated February 9, 2004.
Schedule Page: 326 Line No.: 12 Column: b
November 2010 correction made in 2011.
Schedule Page: 326 Line No.: 12 Column: c
(8) Participation Agreement dated February 9, 2004.
Schedule Page: 326 Line No.: 12 Column: l
November 2010 correction made in 2011.

Schedule Page: 326 Line No.: 13 Column: b
Energy Imbalance

Schedule Page: 326 Line No.: 13 Column: c
(8) Participation Agreement dated February 9, 2004.

Schedule Page: 326 Line No.: 14 Column: b
Energy Imbalance

Schedule Page: 326 Line No.: 14 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4.

Schedule Page: 326.1 Line No.: 1 Column: a
Louisville Gas and Electric Company and Kentucky Utilities Company are owned by PPL Corporation.

Schedule Page: 326.1 Line No.: 1 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.: 2 Column: a
Inter-company Power Agreement dated September 10, 2010. The Company owns 5.63% 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.: 2 Column: b
Surplus Power

Schedule Page: 326.1 Line No.: 2 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.: 3 Column: a
Inter-company Power Agreement dated September 10, 2010. The Company owns 5.63% 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.: 3 Column: b
December 2010 true-up of accrual estimate for both energy and demand charges booked in 2011.

Schedule Page: 326.1 Line No.: 3 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.: 3 Column: l
December 2010 true-up of accrual estimate for both energy ($106,663) and demand charges (($135,897)) made in 2011.

Schedule Page: 326.1 Line No.: 4 Column: b
Market Based Purchase

Schedule Page: 326.1 Line No.: 4 Column: c
(9) EEI Master Power Purchase and Sale Agreeement dated April 27, 2011.

Schedule Page: 326.1 Line No.: 5 Column: b
Energy Imbalance

Schedule Page: 326.1 Line No.: 5 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4.

Schedule Page: 326.1 Line No.: 6 Column: b
Market Based Purchase

Schedule Page: 326.1 Line No.: 6 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.1 Line No.: 7 Column: b
December 2010 correction made in 2011.

Schedule Page: 326.1 Line No.: 7 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

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FOOTNOTE DATA

Schedule Page: 326.1 Line No.: 7 Column: l

December 2010 correction made in 2011.

Schedule Page: 326.1 Line No.: 8 Column: b

Market Based Purchase

Schedule Page: 326.1 Line No.: 8 Column: c

(10) Interchange Agreement dated July 1, 1977.

Schedule Page: 326.1 Line No.: 9 Column: b

Emergency Power

Schedule Page: 326.1 Line No.: 9 Column: c

(4) TEE Contingency Reserve Sharing Agreement dated November 20, 2009.

Schedule Page: 326.1 Line No.: 10 Column: b

Market Based Purchase

Schedule Page: 326.1 Line No.: 10 Column: c

(7) WSPP Rate Schedule FERC No. 6.

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.

Name of Respondent Louisville Gas and Electric 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 456.1)
(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	Indiana Municipal Power Agency	Indiana Municipal Power Agency	MISO and PJM	OLF
5	Indiana Municipal Power Agency	Indiana Municipal Power Agency	MISO and PJM	LFP
6	Illinois Municipal Electric Agency	IL Municipal Electric Agency	Midwest ISO	OLF
7	Illinois Municipal Electric Agency	IL Municipal Electric Agency	Midwest ISO	LFP
8	Cargill Power Markets, LLC	Various	Various	SFP
9	Cargill Power Markets, LLC	Various	Various	AD
10	Cargill Power Markets, LLC	Various	Various	NF
11	LG&E/KU	Various	Various	NF
12	LG&E/KU	Various	Various	AD
13	LG&E/KU	Various	Various	SFP
14	LG&E/KU	Various	Various	LFP
15	Hoosier Energy	Midwest ISO	Hoosier Energy	FNO
16	Kentucky Municipal Power Agency	Midwest ISO	Louisville Gas and Electric	FNO
17	Kentucky Municipal Power Agency	N/A	N/A	OS
18	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	FNO
19	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	LFP
20	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	SFP
21	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	NF
22	Big Rivers Electric Corporation	Big Rivers Electric Corporation	Big Rivers Electric Corporation	FNO
23	The Energy Authority	Various	Various	NF
24	Constellation Energy Commodities Group	PJM	Tennessee Valley Authority	SFP
25	Constellation Energy Commodities Group	PJM	Tennessee Valley Authority	NF
26	Ameren Energy Marketing	Various	Various	SFP
27	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	NF
28	City of Barbourville	Various	City of Barbourville	FNO
29	City of Bardstown	Various	City of Bardstown	FNO
30	City of Bardwell	Various	City of Bardwell	FNO
31	City of Benham	Various	City of Benham	FNO
32	City of Berea	Various	City of Berea	FNO
33	City of Corbin	Various	City of Corbin	FNO
34	City of Falmouth	Various	City of Falmouth	FNO
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	239	332,097	322,361	1
LGE/KU Joint	East Kentucky Power	East Kentucky Power				2
LGE/KU Joint	East Kentucky Power	East Kentucky Power				3
LGE/KU Joint	Trimble Co. Unit 1	PJM and MISO		441,880	441,880	4
LGE/KU Joint	Trimble Co. Unit 2	PJM and MISO		602,643	602,643	5
LGE/KU Joint	Trimble Co. Unit 1	Midwest ISO		419,989	419,989	6
LGE/KU Joint	Trimble Co. Unit 2	Midwest ISO		566,856	566,856	7
LGE/KU Joint	Various	Various	10	40,500	39,315	8
LGE/KU Joint	Various	Various				9
LGE/KU Joint	Various	Various		61	59	10
LGE/KU Joint	Various	Various				11
LGE/KU Joint	Various	Various				12
LGE/KU Joint	Various	Various	182			13
LGE/KU Joint	Various	Various	160			14
LGE/KU Joint	Midwest ISO	Hoosier Energy		39,133	39,133	15
SA 13	Various	LGEE.KMPA	151	227,171	220,615	16
402	N/A	N/A				17
SA 15	Owensboro Municipal	Various	172	1,458		18
LGE/KU Joint	Owensboro Municipal	Various	79	543,942	525,824	19
LGE/KU Joint	Owensboro Municipal	Various	156			20
LGE/KU Joint	Owensboro Municipal	Various				21
LGE/KU Joint	Big Rivers Electric	Big Rivers Electric	7	11,312	10,983	22
LGE/KU Joint	Various	Various		39	38	23
LGE/KU Joint	PJM	TVA	26	42,342	40,925	24
LGE/KU Joint	PJM	TVA				25
LGE/KU Joint	Various	Various		8,843	8,577	26
LGE/KU Joint	TVA	TVA		94	94	27
184	Various	City of Barbourvill	64			28
185	Various	City of Bardstown	137			29
186	Various	City of Bardwell	11			30
187	Various	City of Benham	17			31
197	Various	City of Berea	89			32
188	Various	City of Corbin	57			33
189	Various	City of Falmouth	21			34
			2,343	**3,278,360**	**3,239,292**	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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')

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.
1,418,339		202,451	1,620,790	1
3,774		483	4,257	2
	-1,932		-1,932	3
				4
				5
				6
				7
32,913	78,584	13,522	125,019	8
	84		84	9
	1,642	218	1,860	10
195,208	389,494	58,124	642,826	11
2,713	7,503		10,216	12
653,123		78,181	731,304	13
502,177		66,263	568,440	14
				15
487,849		319,705	807,554	16
-458,866		-75,436	-534,302	17
393,241		324,490	717,731	18
246,119		33,078	279,197	19
466,663		61,005	527,668	20
	182,518	18,773	201,291	21
22,240		2,907	25,147	22
	94	9	103	23
72,336		8,857	81,193	24
	25	2	27	25
	20,517	2,196	22,713	26
	214	22	236	27
68,213		4,234	72,447	28
143,445		8,882	152,327	29
12,006		740	12,746	30
16,804		1,031	17,835	31
93,783		5,814	99,597	32
59,798		3,706	63,504	33
21,144		1,304	22,448	34
5,277,750	**678,743**	**1,191,745**	**7,148,238**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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 Frankfort	Various	City of Frankfort	FNO
2	City of Madisonville	Various	City of Madisonville	FNO
3	City of Nicholasville	Various	City of Nicholasville	FNO
4	City of Paris	Various	City of Paris	FNO
5	City of Providence	Various	City of Providence	FNO
6				
7				
8				
9				
10				
11				
12				
13				
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34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
190	Various	City of Frankfort	414			1
161	Various	City of Madisonvill	177			2
157	Various	City of Nicholasvil	115			3
83	Various	City of Paris	39			4
195	Various	City of Providence	20			5
						6
						7
						8
						9
						10
						11
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						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			2,343	**3,278,360**	**3,239,292**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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')

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.
445,720		27,664	473,384	1
191,174		11,863	203,037	2
123,630		7,672	131,302	3
42,254		2,622	44,876	4
21,950		1,363	23,313	5
				6
				7
				8
				9
				10
				11
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				26
				27
				28
				29
				30
				31
				32
				33
				34
5,277,750	**678,743**	**1,191,745**	**7,148,238**	

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 Louisville Gas and Electric Company, Kentucky Utilities 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: a

Louisville Gas and Electric Company (LG&E) transmits electricity for Indiana Municipal Power Agency (IMPA) from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMPA. This agreement was reached between LG&E and IMPA as a result of LG&E's exit from the MISO.

Schedule Page: 328 Line No.: 4 Column: d

The OLF transmission service agreement between Louisville Gas and Electric Company and Indiana Municipal Power Agency has no expiration date.

Schedule Page: 328 Line No.: 5 Column: a

Louisville Gas and Electric Company (LG&E) transmits electricity for Indiana Municipal Power Agency (IMPA) from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMPA. This agreement was reached between LG&E and IMPA as a result of LG&E's exit from the MISO.

Schedule Page: 328 Line No.: 5 Column: d

The LFP transmission service agreement between Louisville Gas and Electric Company and Indiana Municipal Power Agency has a termination date of 1/01/2020 for Trimble County Unit 2.

Schedule Page: 328 Line No.: 6 Column: a

Louisville Gas and Electric Company (LG&E) transmits electricity for Illinois Municipal Electric Agency (IMEA) from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMEA. This agreement was reached between LG&E and IMEA as a result of LG&E's exit from the MISO.

Schedule Page: 328 Line No.: 6 Column: d

The OLF transmission service agreement between Louisville Gas and Electric Company and Illinois Municipal Electric Agency has a termination date of 3/01/2023 for Trimble County Unit 1.

Schedule Page: 328 Line No.: 7 Column: a

Louisville Gas and Electric Company (LG&E) transmits electricity for Illinois Municipal Electric Agency (IMEA) from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMEA. This agreement was reached between LG&E and IMEA as a result of LG&E's exit from the MISO.

Schedule Page: 328 Line No.: 7 Column: d

The LFP transmission service agreement between Louisville Gas and Electric Company and Illinois Municipal Electric Agency has a termination date of 1/01/2020 for Trimble County Unit 2.

Schedule Page: 328 Line No.: 8 Column: m

The total consists of Cargill Power Markets, LLC Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 9 Column: l

The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 10 Column: m

The total consists of Cargill Power Markets, LLC Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 11 Column: a

Louisville Gas and Electric Company and Kentucky Utilities Company are owned by PPL

Corporation.

Schedule Page: 328 Line No.: 11 Column: m

The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 12 Column: a

Louisville Gas and Electric Company and Kentucky Utilities Company are owned by PPL Corporation.

Schedule Page: 328 Line No.: 12 Column: l

The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 13 Column: a

Louisville Gas and Electric Company and Kentucky Utilities Company are owned by PPL Corporation.

Schedule Page: 328 Line No.: 13 Column: m

The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 14 Column: a

Louisville Gas and Electric Company and Kentucky Utilities Company are owned by PPL Corporation.

Schedule Page: 328 Line No.: 14 Column: d

Long-term Firm purchases by Louisville Gas and Electric Company and Kentucky Utilities 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.: 14 Column: m

The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 16 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.: 17 Column: k

The amount consists of Kentucky Municipal Power Agency depancaking credits related to Louisville Gas and Electric Company's exit from the MISO, pursuant to Rate Schedule 402 as filed with and accepted by the FERC.

Schedule Page: 328 Line No.: 17 Column: m

The amount consists of Kentucky Municipal Power Agency Schedule 1 and Schedule 2 charges for depancaking credits related to Louisville Gas and Electric Company's exit from the MISO, pursuant to Rate Schedule 402 as filed with and accepted by the FERC.

Schedule Page: 328 Line No.: 18 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.: 19 Column: m

The total consists of Owensboro Municipal Utilities Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 20 Column: m

The total consists of Owensboro Municipal Utilities Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 21 Column: m

The total consists of Owensboro Municipal Utilities Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 22 Column: m

The total consists of Big Rivers Electric Corporation Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 23 Column: m

The total consists of The Energy Authority Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 24 Column: m

The total consists of Constellation Energy Commodities Group Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 25 Column: m

The total consists of Constellation Energy Commodities Group Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 26 Column: m

The total consists of Ameren Marketing Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 27 Column: m
The total consists of Tennessee Valley Authority Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 28 Column: m
The total consists of City of Barbourville Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 29 Column: m
The total consists of City of Bardstown Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 30 Column: m
The total consists of City of Bardwell Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 31 Column: m
The total consists of City of Benham Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 32 Column: m
The total consists of City of Berea Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 33 Column: m
The total consists of City of Corbin Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 34 Column: m
The total consists of City of Falmouth Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 1 Column: m
The total consists of City of Frankfort Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 2 Column: m
The total consists of City of Madisonville Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 3 Column: m
The total consists of City of Nicholasville Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 4 Column: m
The total consists of City of Paris Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 5 Column: m
The total consists of City of Providence Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 5 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)	$ 7,148,238
Elimination of intracompany transmission revenues	(1,527,454)
Page 300, line 22, column (b)	$ 5,620,784

Name of Respondent Louisville Gas and Electric 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 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	AD				1,432	164	1,596
2	LG&E/KU	LFP	740,350	740,350	1,162,064		87,545	1,249,609
3	LG&E/KU	SFP	844,048	844,048	1,638,018		114,854	1,752,872
4	LG&E/KU	NF	575,058	575,058		1,688,522	95,106	1,783,628
5	PJM Interconnect	NF	15,697	15,697		10,535	60,904	71,439
6	PJM Interconnect	AD			-4	-31	-5,488	-5,523
7	Tennessee Valley Auth	AD				-63		-63
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		2,175,153	2,175,153	2,800,078	1,700,395	353,085	4,853,558

Schedule Page: 332 Line No.: 1 Column: f

The total consists of true-ups of charges for prior periods.

Schedule Page: 332 Line No.: 1 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.: 2 Column: a

LG&E and KU are owned by PPL Corporation.

Schedule Page: 332 Line No.: 2 Column: b

Long-term Firm purchases by LG&E and KU 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.: 2 Column: g

The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 3 Column: a

LG&E and KU are owned by PPL Corporation.

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: a

LG&E and KU are owned by PPL Corporation.

Schedule Page: 332 Line No.: 4 Column: g

The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 5 Column: g

The total consists of Schedule 1, Schedule 2, Black Start Service and charges for other non-firm point-to-point without energy.

Schedule 1 Non-firm:	$ 42,822
Schedule 2 Non-firm:	7,340
Black Start Service Non-firm:	783
Non-firm point-to-point without energy:	9,956
Rounding	3
	$ 60,904

Schedule Page: 332 Line No.: 6 Column: e

The total consists of true-ups of charges for prior periods.

Schedule Page: 332 Line No.: 6 Column: f

The total consists of true-ups of charges for prior periods.

Schedule Page: 332 Line No.: 6 Column: g

The total consists of true-ups of prior period Schedule 1, Schedule 2, Black Start Service and other charges for non-firm point-to-point without energy.

Schedule 1 Non-firm:	$ (1,280)
Schedule 2 Non-firm:	(1,100)
Black Start Service Non-firm:	15
Non-firm point-to-point without energy:	(3,123)
	$ (5,488)

Schedule Page: 332 Line No.: 7 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
Louisville Gas and Electric 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	313,499
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	1,523,755
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	11,630
6	Market Research and Consulting Expenses	
7	Bellomy Research	44,319
8	Experian Marketing Solutions	24,570
9	Kforce Inc.	15,013
10	IBEW Non - Billable Charges	79,549
11	Swap Termination Amortization	205,799
12		
13		
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45		
46	TOTAL	2,218,134

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					
2	Steam Production Plant	71,703,431	2,050,928			73,754,359
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	606,468	1,749			608,217
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	8,488,827	1,110			8,489,937
7	Transmission Plant	5,565,810	862			5,566,672
8	Distribution Plant	22,937,359	6,034			22,943,393
9	Regional Transmission and Market Operation					
10	General Plant	224,775				224,775
11	Common Plant-Electric	9,333,004	1,463	5,774,759		15,109,226
12	TOTAL	118,859,674	2,062,146	5,774,759		126,696,579

B. Basis for Amortization Charges

ACCOUNT	RATE	PLANT BALANCE @ 12/31/2011	AMORTIZATION	
330300	20%	18,699,664	2,673,000	
330310	10%	44,348,601	3,101,759	

			5,774,759	Column (d)
			========	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	Electric Plant						
13	Elec Intangible Plant	2					
14	Steam Production Plant						
15	310.20 - Land	6,293					
16							
17	311 Strctrs & Imprvmts						
18	0112 Cane Run Unit 1	4,233	100.00	-10.00		100-S4	
19	0121 Cane Run Unit 2	2,102	100.00	-10.00		100-S4	
20	0131 Cane Run Unit 3	3,537	100.00	-10.00		100-S4	
21	0141 Cane Run Unit 4	4,085	100.00	-10.00	1.14	100-S4	11.40
22	0142 Cane Run 4 FGD	760	100.00	-10.00	0.95	100-S4	11.30
23	0151 Cane Run Unit 5	6,266	100.00	-10.00	1.92	100-S4	15.20
24	0152 Cane Run 5 FGD	1,696	100.00	-10.00	1.56	100-S4	15.20
25	0161 Cane Run Unit 6	27,477	100.00	-10.00	2.13	100-S4	16.30
26	0162 Cane Run 6 FGD	2,004	100.00	-10.00	2.04	100-S4	16.30
27	0211 Mill Creek Unit 1	19,891	100.00	-10.00	1.64	100-S4	19.00
28	0212 Mill Creek 1 FGD	1,710	100.00	-10.00	1.65	100-S4	19.00
29	0221 Mill Creek Unit 2	11,533	100.00	-10.00	1.42	100-S4	18.90
30	0222 Mill Creek 3 FGD	1,393	100.00	-10.00	1.81	100-S4	19.00
31	0231 Mill Creek Unit 3	24,500	100.00	-10.00	1.51	100-S4	27.80
32	0232 Mill Creek 3 FGD	363	100.00	-10.00	1.47	100-S4	27.70
33	0241 Mill Creek Unit 4	64,263	100.00	-10.00	1.85	100-S4	28.20
34	0242 Mill Creek 4 FGD	5,331	100.00	-10.00	1.76	100-S4	28.10
35	0311 Trimble Cty 1	115,105	100.00	-10.00	2.08	100-S4	28.60
36	0312 Trimble Cty 1 FGD	494	100.00	-10.00	2.28	100-S4	28.70
37	0321 Trimble Cty 2	25,994	100.00	-5.00	2.10	100-S1.5	
38							
39	312 Boiler Plant Eqpmt						
40	0103 Cane Rune Loco	52	25.00	20.00	2.67	25-R2	3.20
41	0104 Cane Run Rail Crs	1,502	25.00	20.00	3.14	25-R2	12.40
42	0112 Cane Run Unit 1	1,052	45.00	-30.00		45-R1.5	
43	0121 Cane Run Unit 2	132	45.00	-30.00		45-R1.5	
44	0131 Cane Run Unit 3	705	45.00	-30.00		45-R1.5	
45	0141 Cane Run Unit 4	31,343	45.00	-30.00	5.88	45-R1.5	10.50
46	0142 Cane Run 4 FGD	17,050	45.00	-30.00	4.93	45-R1.5	10.50
47	0151 Cane Run Unit 5	40,807	45.00	-30.00	6.11	45-R1.5	13.60
48	0152 Cane Run 5 FGD	28,112	45.00	-30.00	4.07	45-R1.5	13.40
49	0161 Cane Run Unit 6	55,220	45.00	-30.00	5.19	45-R1.5	14.10
50	0162 Cane Run 6 FGD	32,459	45.00	-30.00	4.46	45-R1.5	14.20

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	0203 Mill Creek Loco	613	25.00	20.00	2.90	25-R2	5.10
13	0204 Mill Ck Rail Cars	2,965	25.00	20.00	3.13	25-R2	12.00
14	0211 Mill Creek Unit 1	56,257	45.00	-30.00	4.24	45-R1.5	15.80
15	0212 Mill Creek 1 FGD	43,570	45.00	-30.00	4.50	45-R1.5	16.30
16	0221 Mill Creek Unit 2	53,299	45.00	-30.00	4.70	45-R1.5	16.10
17	0222 Mill Creek 2 FGD	35,720	45.00	-30.00	4.28	45-R1.5	16.30
18	0231 Mill Creek Unit 3	143,061	45.00	-30.00	3.87	45-R1.5	21.10
19	0232 Mill Creek 3 FGD	63,257	45.00	-30.00	3.85	45-R1.5	21.90
20	0241 Mill Creek Unit 4	248,201	45.00	-30.00	3.85	45-R1.5	21.40
21	0242 Mill Creek 4 FGD	114,257	45.00	-30.00	3.71	45-R1.5	22.00
22	0311 Trimble Cty 1	217,218	45.00	-30.00	3.62	45-R1.5	21.90
23	0312 Trimble Cty 1 FGD	63,633	45.00	-30.00	3.62	45-R1.5	21.50
24	0321 Trimble Cty 2	121,586	65.00	-20.00	4.28	65-R2	
25	0322 Trimble 2 FGD	14,269	65.00	-20.00	4.28	65-R2	
26							
27	314 Turbogenerator Unt						
28	0112 Cane Run Unit 1	106	50.00	-10.00		50-S1.5	
29	0121 Cane Run Unit 2	20	50.00	-10.00		50-S1.5	
30	0131 Cane Run Unit 3	581	50.00	-10.00		50-S1.5	
31	0141 Cane Run Unit 4	9,319	50.00	-10.00	3.09	50-S1.5	10.80
32	0151 Cane Run Unit 5	7,932	50.00	-10.00	2.22	50-S1.5	13.30
33	0161 Cane Run Unit 6	16,729	50.00	-10.00	3.29	50-S1.5	15.10
34	0211 Mill Creek Unit 1	14,686	50.00	-10.00	2.15	50-S1.5	15.70
35	0221 Mill Creek Unit 2	17,091	50.00	-10.00	2.46	50-S1.5	16.30
36	0231 Mill Creek Unit 3	31,675	50.00	-10.00	2.15	50-S1.5	20.80
37	0241 Mill Creek Unit 4	42,573	50.00	-10.00	2.29	50-S1.5	21.80
38	0311 Trimble Cty 1	57,001	50.00	-10.00	2.48	50-S1.5	23.10
39	0321 Trimble Cty 2	20,447	55.00	-15.00	2.78	55-R2.5	
40							
41	315 Accessry Elec Eqpm						
42	0112 Cane Run Unit 1	1,884	50.00	-5.00		50-S2	
43	0121 Cane Run Unit 2	1,238	50.00	-5.00		50-S2	
44	0131 Cane Run Unit 3	767	50.00	-5.00		50-S2	
45	0141 Cane Run Unit 4	5,921	50.00	-5.00	3.18	50-S2	11.30
46	0142 Cane Run 4 FGD	988	50.00	-5.00	0.82	50-S2	10.20
47	0151 Cane Run Unit 5	9,435	50.00	-5.00	2.97	50-S2	15.00
48	0152 Cane Run 5 FGD	2,216	50.00	-5.00	1.49	50-S2	13.40
49	0161 Cane Run Unit 6	12,602	50.00	-5.00	2.80	50-S2	15.70
50	0162 Cane Run 6 FGD	2,200	50.00	-5.00	1.44	50-S2	13.90

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	0211 Mill Creek Unit 1	15,688	50.00	-5.00	2.75	50-S2	18.20
13	0212 Mill Creek 1 FGD	5,542	50.00	-5.00	1.67	50-S2	16.00
14	0221 Mill Creek Unit 2	7,415	50.00	-5.00	2.03	50-S2	17.10
15	0222 Mill Creek 2 FGD	4,505	50.00	-5.00	1.69	50-S2	16.00
16	0231 Mill Creek Unit 3	15,049	50.00	-5.00	1.58	50-S2	19.40
17	0232 Mill Creek 3 FGD	2,532	50.00	-5.00	1.56	50-S2	19.20
18	0241 Mill Creek Unit 4	24,033	50.00	-5.00	1.75	50-S2	20.70
19	0242 Mill Creek 4 FGD	5,865	50.00	-5.00	1.71	50-S2	20.40
20	0311 Trimble Cty 1	49,159	50.00	-5.00	2.13	50-S2	23.50
21	0312 Trimble Cty 1 FGD	2,737	50.00	-5.00	2.12	50-S2	23.50
22	0321 Trimble Cty 2	8,303	70.00	-5.00	2.49	70-S3	
23							
24	316 Misc Plant Equipmt						
25	0112 Cane Run Unit 1	39	40.00	-5.00		40-S2	
26	0131 Cane Run Unit 3	12	40.00	-5.00		40-S2	
27	0141 Cane Run Unit 4	87	40.00	-5.00	6.30	40-S2	11.30
28	0142 Cane Run 4 FGD	6	40.00	-5.00	2.83	40-S2	9.00
29	0151 Cane Run Unit 5	97	40.00	-5.00	5.40	40-S2	15.20
30	0152 Cane Run 5 FGD	47	40.00	-5.00	2.85	40-S2	11.60
31	0161 Cane Run Unit 6	2,931	40.00	-5.00	4.32	40-S2	15.20
32	0162 Cane Run 6 FGD	32	40.00	-5.00	2.75	40-S2	11.60
33	0211 Mill Creek Unit 1	740	40.00	-5.00	3.22	40-S2	14.40
34	0221 Mill Creek Unit 2	126	40.00	-5.00	2.90	40-S2	13.70
35	0231 Mill Creek Unit 3	410	40.00	-5.00	2.59	40-S2	14.60
36	0241 Mill Creek Unit 4	7,285	40.00	-5.00	3.04	40-S2	22.40
37	0242 Mill Creek 4 FGD	75	40.00	-5.00	2.83	40-S2	18.00
38	0311 Trimble Cty 1	2,918	40.00	-5.00	2.89	40-S2	20.80
39	0321 Trimble Cty 2	1,540	70.00		3.00	70-R1.5	
40							
41	317 Asset Rtiremt Oblg	27,798					
42							
43	Hydraulic Prodctn Plnt						
44	Project 289						
45	0451 - Ohio Falls						
46	330.20 Land						
47	331 Structrs & Imprvmt	4,898	100.00	-5.00	0.08	100-S2.5	29.50
48	332 Resrvrs Dams Wtrty	11,690	10.00	-5.00	3.30	100-S2.5	29.40
49	333 Wtr Whls Trbns Gen	19,945	10.00	-10.00	0.25	100-S2	29.40
50	334 Accessry Elec Eqpt	5,510	80.00	-5.00	2.94	80-S4	29.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	335 Misc Pwr Plnt Eqpm	285	80.00	-10.00	2.29	80-S3	27.20
13	336 Rds Railrds Bridge	29	80.00			80-S4	
14							
15	Hydraulic Prodctn Plnt						
16	Other Than Proj 289						
17	0450 - Ohio Falls						
18	330.20 Land						
19	331 Structrs & Imprvmt	66	100.00	-5.00	0.53	100-S2.5	29.40
20	335 Misc Pwr Plnt Eqpm	25	80.00	-10.00	1.61	80-S3	24.60
21	336 Rds Railrds Bridge	1	80.00			80-S4	
22	337 Asset Retirmt Oblg	103					
23							
24	Other Production Plant						
25	340.20 - Land	8					
26							
27	341 Strctrs & Imprvmnt						
28	0171 Cane Run GT 11	212	55.00	-5.00	1.34	55-R3	3.40
29	0410 Zorn and River	8	55.00	-5.00	0.61	55-R3	3.30
30	0431 Paddys Run Gen 12	64	55.00	-5.00	0.60	55-R3	3.30
31	0432 Paddys Run Gen 13	2,159	55.00	-5.00	3.05	55-R3	27.60
32	0459 Brown CT5	859	55.00	-5.00	3.05	55-R3	27.60
33	0460 Brown CT6	106	55.00	-5.00	3.17	55-R3	27.60
34	0461 Brown CT7	144	55.00	-5.00	3.12	55-R3	27.60
35	0470 Trimble Cty CT5	1,556	55.00	-5.00	3.16	55-R3	27.70
36	0471 Trimble Cty CT6	1,468	55.00	-5.00	3.14	55-R3	27.70
37	0474 Trimble Cty CT7	2,083	55.00	-5.00	3.34	55-R3	27.80
38	0475 Trimble Cty CT8	2,075	55.00	-5.00	3.34	55-R3	27.80
39	0476 Trimble Cty CT9	2,137	55.00	-5.00	3.34	55-R3	27.80
40	0477 Trimble Cty CT10	2,133	55.00	-5.00	3.34	55-R3	27.80
41							
42	342 Fuel Holders Prdcr						
43	0171 Cane Run GT 11	319	55.00	-5.00	3.85	55-R3	3.50
44	0410 Zorn and River	23	55.00	-5.00	0.59	55-R3	3.30
45	0430 Paddys Run Gen 11	9	55.00	-5.00	0.58	55-R3	3.30
46	0431 Paddys Run Gen 12	22	55.00	-5.00	0.85	55-R3	3.40
47	0432 Paddys Run Gen 13	2,255	55.00	-5.00	3.08	55-R3	27.10
48	0459 Brown CT5	847	55.00	-5.00	3.07	55-R3	27.10
49	0460 Brown CT6	403	55.00	-5.00	2.99	55-R3	26.90
50	0461 Brown CT7	141	55.00	-5.00	2.99	55-R3	26.90

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	0470 Trimble Cty CT5	98	55.00	-5.00	3.17	55-R3	27.20
13	0471 Trimble Cty CT6	98	55.00	-5.00	3.17	55-R3	27.20
14	0473 Trim Cty Pipeline	1,998	55.00	-5.00	3.19	55-R3	27.30
15	0474 Trimble Cty CT7	339	55.00	-5.00	3.36	55-R3	27.40
16	0475 Trimble Cty CT8	338	55.00	-5.00	3.36	55-R3	27.40
17	0476 Trimble Cty CT9	347	55.00	-5.00	3.36	55-R3	27.40
18	0477 Trimble Cty CT10	362	55.00	-5.00	3.36	55-R3	27.40
19							
20	343 Prime Movers						
21	0432 Paddys Run Gen 13	20,146	30.00	-5.00	3.84	30-R2	19.10
22	0459 Brown CT5	15,878	30.00	-5.00	3.84	30-R2	19.10
23	0460 Brown CT6	19,952	30.00	-5.00	3.85	30-R2	18.80
24	0461 Brown CT7	18,240	30.00	-5.00	3.81	30-R2	18.50
25	0470 Trimble Cty CT5	16,268	30.00	-5.00	3.88	30-R2	19.40
26	0471 Trimble Cty CT6	13,120	30.00	-5.00	3.88	30-R2	19.40
27	0474 Trimble Cty CT7	13,611	30.00	-5.00	3.99	30-R2	19.80
28	0475 Trimble Cty CT8	13,497	30.00	-5.00	3.99	30-R2	19.80
29	0476 Trimble Cty CT9	13,407	30.00	-5.00	3.99	30-R2	19.80
30	0477 Trimble Cty CT10	13,353	30.00	-5.00	3.99	30-R2	19.80
31							
32	344 Generators						
33	0171 Cane Run GT 11	2,910	60.00	-5.00	5.73	60-S3	3.50
34	0410 Zorn and River	1,828	60.00	-5.00	2.70	60-S3	3.50
35	0430 Paddys Run Gen 11	1,523	60.00	-5.00	2.74	60-S3	3.50
36	0431 Paddys Run Gen 12	2,992	60.00	-5.00	2.63	60-S3	3.50
37	0432 Paddys Run Gen 13	5,860	60.00	-5.00	3.00	60-S3	29.20
38	0459 Brown CT 5	3,249	60.00	-5.00	3.00	60-S3	29.20
39	0460 Brown CT 6	2,418	60.00	-5.00	2.91	60-S3	29.10
40	0461 Brown CT7	2,421	60.00	-5.00	2.91	60-S3	29.10
41	0470 Trimble Cty CT 5	1,539	60.00	-5.00	3.09	60-S3	29.30
42	0471 Trimble Cty CT 6	1,537	60.00	-5.00	3.09	60-S3	29.30
43	0474 Trimble Cty CT 7	1,727	60.00	-5.00	3.28	60-S3	29.30
44	0475 Trimble Cty CT 8	1,717	60.00	-5.00	3.28	60-S3	29.40
45	0476 Trimble Cty CT 9	1,728	60.00	-5.00	3.28	60-S3	29.30
46	0477 Trimble Cty CT 10	1,723	60.00	-5.00	3.28	60-S3	29.30
47							
48	345 Accssry Elec Eqpmt						
49	0171 Cane Run GT 11	117	35.00		2.40	35-S1.5	3.10
50	0410 Zorn & River	44	35.00		2.31	35-S1.5	3.00

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	0430 Paddys Run Gen 11	68	35.00		4.27	35-S1.5	3.30
13	0431 Paddys Run Gen 12	913	35.00		3.82	35-S1.5	3.20
14	0432 Paddys Run Gen 13	2,779	35.00		3.32	35-S1.5	21.80
15	0459 Brown CT 5	2,588	35.00		3.32	35-S1.5	21.80
16	0460 Brown CT 6	970	35.00		3.26	35-S1.5	2.00
17	0461 Brown CT 7	954	35.00		3.26	35-S1.5	21.30
18	0470 Trimble Cty CT 5	707	35.00		3.38	35-S1.5	22.30
19	0471 Trimble Cty CT 6	1,595	35.00		3.38	35-S1.5	22.30
20	0474 Trimble Cty CT 7	1,843	35.00		3.52	35-S1.5	23.40
21	0475 Trimble Cty CT 8	1,836	35.00		3.52	35-S1.5	23.40
22	0476 Trimble Cty CT 9	1,891	35.00		3.52	35-S1.5	23.40
23	0477 Trimble Cty CT 10	4,388	35.00		3.52	35-S1.5	23.40
24							
25	346 Misc Plant Equipmt						
26	0410 Zorn & River	9	50.00			50-S3	
27	0430 Paddys Run Gen 11	9	50.00			50-S3	
28	0432 Paddys Run Gen 13	1,281	50.00		2.81	50-S3	28.60
29	0459 Brown CT 5	2,395	50.00		2.81	50-S3	28.60
30	0460 Brown CT 6	23	50.00		2.86	50-S3	28.70
31	0461 Brown CT 7	23	50.00		2.86	50-S3	28.70
32	0470 Trimble Cty CT 5	15	50.00		3.22	50-S3	29.00
33	0474 Trimble Cty CT 7	6	50.00		3.11	50-S3	29.00
34	0475 Trimble Cty CT 8	5	50.00		3.11	50-S3	29.00
35	0476 Trimble Cty CT 9	5	50.00		3.12	50-S3	29.10
36	0477 Trimble Cty CT 10	25	50.00		3.10	50-S3	29.00
37							
38	347 Asset Retirmt Obli	38					
39							
40	Elec Trnsmsn Plant						
41	350.20 Trnsmsn Lines L	1,573					
42	350.10 Land Rights	7,781	50.00		3.92	50-R3	12.80
43	352.10 Strctr&Imprvmts	6,457	60.00	-10.00	1.17	60-R2.5	40.20
44	353.10 Station Equipmt	127,565	55.00	-10.00	1.32	55-R2.5	34.30
45	354 Towers & Fixtures	40,070	65.00	-40.00	1.38	65-R3	36.70
46	355 Poles & Fixtures	53,282	50.00	-50.00	2.95	50-R2	29.40
47	356 Ovrhead Cndctrs&Dv	47,242	50.00	-40.00	2.52	50-R2	27.20
48	357 Undrground Conduit	2,437	50.00		1.85	50-R3	35.80
49	358 Undrgrnd Cndctrs&D	5,660	30.00		3.65	50-R3	16.80
50	359 Transmission ARO's	253					

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							
13	Distribution Plant						
14	360.20 Substation Land	4,111					
15	361 Substation Strctrs	4,258	60.00	-20.00	1.01	60-R3	39.00
16	362.10 Substation Eqpm	106,268	55.00	-20.00	1.01	55-R1.5	32.00
17	362.10 Sbst Eqpm Futur		55.00	-20.00		55-R1.5	32.00
18	364 Poles Twrs & Fxtur	135,482	50.00	-60.00	3.00	50-R2.5	29.10
19	365 Ovrhd Cndctrs&Dvcs	234,013	45.00	-50.00	2.90	45-R1.5	26.30
20	366 Undrgrnd Conduit	69,528	70.00	-10.00	1.25	70-R4	54.80
21	367 Undrgrnd Cndctrs&D	145,472	50.00	-15.00	1.76	50-R2	31.80
22	368.10 Line Trnsformr	140,346	45.00	-20.00	2.18	45-R1.5	25.20
23	369.10 Undrgrnd Srvcs	6,153	45.00	-35.00	2.45	45-R1.5	26.80
24	369.20 Ovrhead Srvcs	21,115	45.00	-100.00	4.99	45-R1.5	21.50
25	370.10 Meters	37,656	30.00	-5.00	3.79	30-R2	13.10
26	373.10 Ovrhd St Lightn	34,508	30.00	-20.00	2.77	30-L1	15.30
27	373.20 Undrgrd St Lght	48,189	35.00	-20.00	2.95	35-R1.5	21.00
28	373.40 St Lghtg Trnsfr		26.00			26-R0.5	
29	374 ARO Distribution	626					
30							
31	General Plant						
32	392.10 Trnsprtatn Eqp	8,185			20.00		
33	392.20 Trnsprtatn Trlr	607	30.00	5.00	3.62	30-S4	15.90
34	394 Tools Shp Grage Eq	4,604	25.00		4.39	25-SQ	15.80
35	395 Laboratory Equipmt		15.00		30.32	15-SQ	1.50
36	396.10 Pwr Op Eqp Hrly	2,403			20.00		
37	396.20 Pwr Op Eqp Oth	151	30.00		3.17	30-R1.5	15.30
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	471,098		471,098	
3	Administrative Charge, Project #289	186,047		186,047	
4					
5	Kentucky Public Service Commission				
6	2008 Rate Case - Electric (Mar-09 to Feb-12)		247,757	247,757	289,049
7	2008 Rate Case - Gas (Mar-09 to Feb-12)		82,993	82,993	96,825
8					
9	2009 Rate Case - Electric (Aug-10 to Jul-13)		279,832	279,832	722,898
10	2009 Rate Case - Gas (Aug-10 to Jul-13)		160,142	160,142	413,700
11					
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45					
46	TOTAL	657,145	770,724	1,427,869	1,522,472

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	471,098					2
Electric	928	186,047					3
							4
							5
Electric	928	247,757		928	247,757	41,293	6
Gas	928	82,993		928	82,993	13,832	7
							8
Electric	928	279,832		928	279,832	443,066	9
Gas	928	160,142		928	160,142	253,558	10
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		1,427,869			770,724	751,749	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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)	Evaluation of Geologic Carbon Storage
10	University of Kentucky Research Foundation (4)	Amortization of Carbon Capturing Research Regulatory Asset
11	Moore Ventures LLC (4)	Biomass Feasibility Study
12	Seismic Specialists Inc. (4)	Geological Survey
13	University of Texas at Austin, The (4)	Annual Subscription to the Luminant Carbon Management Program
14	Gottuso, Leeann (4)	Engineering Studies
15	Meiners Electric (4)	EPRI Project
16	Kellogg Brown and Root, LLC (4)	Carbon Capture Project
17	Youngblood Construction (4)	Engineering Studies
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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		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
	1,348	500	1,348		1
	2,400	510	2,400		2
	1,167	566	1,167		3
	56,530	908	56,530		4
	11,888	923	11,888		5
	466,535	930	466,535		6
	721,238	930	721,238		7
	219,510	930	219,510		8
	10,673	923	10,673		9
	97,560	930	97,560		10
	7,529	923	7,529		11
	7,400	923	7,400		12
	14,250	930	14,250		13
	44	930	44		14
	4,534	930	4,534		15
	128,491	923	128,491		16
	84	930	84		17
					18
	1,751,181		1,751,181		19
					20
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	21,545,763		
4	Transmission	2,696,671		
5	Regional Market			
6	Distribution	8,011,827		
7	Customer Accounts	3,440,063		
8	Customer Service and Informational	670,472		
9	Sales			
10	Administrative and General	12,709,457		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	49,074,253		
12	Maintenance			
13	Production	11,221,975		
14	Transmission	302,086		
15	Regional Market			
16	Distribution	3,216,028		
17	Administrative and General	3,290,872		
18	TOTAL Maintenance (Total of lines 13 thru 17)	18,030,961		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	32,767,738		
21	Transmission (Enter Total of lines 4 and 14)	2,998,757		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	11,227,855		
24	Customer Accounts (Transcribe from line 7)	3,440,063		
25	Customer Service and Informational (Transcribe from line 8)	670,472		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	16,000,329		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	67,105,214	17,092,770	84,197,984
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	488,981		
34	Storage, LNG Terminaling and Processing	1,609,976		
35	Transmission	420,405		
36	Distribution	3,051,658		
37	Customer Accounts	2,814,445		
38	Customer Service and Informational	256,661		
39	Sales			
40	Administrative and General	3,011,211		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	11,653,337		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	1,187,267		
47	Transmission	166,207		

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Louisville Gas and Electric 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	4,602,226		
49	Administrative and General	1,344,108		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	7,299,808		
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)	488,981		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	2,797,243		
56	Transmission (Lines 35 and 47)	586,612		
57	Distribution (Lines 36 and 48)	7,653,884		
58	Customer Accounts (Line 37)	2,814,445		
59	Customer Service and Informational (Line 38)	256,661		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	4,355,319		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	18,953,145	6,283,770	25,236,915
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	86,058,359	23,376,540	109,434,899
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	7,863,783	7,010,624	14,874,407
69	Gas Plant	3,079,908	3,913,281	6,993,189
70	Other (provide details in footnote):	1,318,608	449,761	1,768,369
71	TOTAL Construction (Total of lines 68 thru 70)	12,262,299	11,373,666	23,635,965
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,038,349	660,138	1,698,487
74	Gas Plant	187,466	122,392	309,858
75	Other (provide details in footnote):	1,789	664	2,453
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,227,604	783,194	2,010,798
77	Other Accounts (Specify, provide details in footnote):			
78	Accounts Receivable (work done for others)	6,008,094	1,570,655	7,578,749
79	Miscellaneous Deferred Debits	34,829	838,317	873,146
80	Certain Civic, Political and Related Activities and Other	451,538	153,210	604,748
81	Accounts Receivable (Non-jurisdictional- Trimble County)	1,411,813	394,429	1,806,242
82				
83				
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93				
94				
95	TOTAL Other Accounts	7,906,274	2,956,611	10,862,885
96	TOTAL SALARIES AND WAGES	107,454,536	38,490,011	145,944,547

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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.

(1) See attached sheet, page 356.1.

(2) See attached sheet, page 356.1.

(3) Depreciation - Electric $9,334,467; Gas $3,809,186. Amortization - Electric $5,774,759; Gas $2,358,705.

Common Utility expense accounts are not maintained, but such expenses are allocated to Electric and Gas Departments as follows:

Customer Accounts Expenses (excluding for uncollectable accounts).

Allocated between departments based on average number of customers served by each department for the year ending December 31, 2010.

Customer Service and Informational Expenses.

Allocated between departments based on gross revenues from ultimate consumers by departments for the twelve month period.

Administrative and General Expenses

The administrative and general expenses are allocated on the basis of total direct costs.

(4) The property original cost studies made pursuant to the Uniform System of Accounts included a separate classification for Common Utility Plant. Orders were issued in connection with such studies by Public Service Commission of Kentucky on September 16, 1941, and January 5, 1945, and the Federal Power Commission on December 15, 1944.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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.

Common Utility Plant (1)

	Allocation to Utility Department (2) Electric 71%	Gas 29%	Balance End of Year
Accounts 101 and 106			
Intangible Plant			
301 Organization			$ 83,782
303 Miscellaneous Intangible Plant			63,048,265
Total Intangible Plant			$ 63,132,047
General Plant			
389 Land and Land Rights			$ 1,887,411
390 Structures and Improvements			74,128,523
391 Office and Furniture and Equipment			30,400,930
392 Transportation Equipment			328,971
393 Stores Equipment			1,135,864
394 Tools, Shop and Garage Equipment			3,619,510
396 Power Operated Equipment			249,978
397 Communication Equipment			47,757,628
398 Miscellaneous Equipment			21,816
399 ARO Common Plant			101,390
Total Common Plant			$ 159,632,021
Total Accounts 101 and 106			$ 222,764,068
Account 107			15,083,939
Total Common Utility Plant	$ 168,872,085	$ 68,975,922	$ 237,848,007

Accumulated Provision for Depreciation and Amortization of Common Utility Plant

	Electric	Gas	Total
Balance at end of year	$ 69,133,176	$ 28,237,495	$ 97,370,671

(1) Common plant consists of land, structures and equipment of a general nature used by all departments not specifically assignable to one department, and includes offices, storerooms, communication, transportation and work equipment, etc.

(2) Based on estimated usage by departments.

Name of Respondent Louisville Gas and Electric 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)	4,255	300,571	867,694	868,440
3	Net Sales (Account 447)	13,412,193	20,307,935	26,975,254	43,903,501
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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45					
46	TOTAL	13,416,448	20,608,506	27,842,948	44,771,941

Schedule Page: 397 Line No.: 2 Column: b

The amount reflects transactions recorded in accordance with Louisville Gas and Electric Company's Power Supply System Agreement with Kentucky Utilities 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 $4,091.

Schedule Page: 397 Line No.: 2 Column: c

The amount reflects transactions recorded in accordance with Louisville Gas and Electric Company's Power Supply System Agreement with Kentucky Utilities 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 $300,407.

Schedule Page: 397 Line No.: 2 Column: d

The amount reflects transactions recorded in accordance with Louisville Gas and Electric Company's Power Supply System Agreement with Kentucky Utilities 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 $866,742.

Schedule Page: 397 Line No.: 2 Column: e

The amount reflects transactions recorded in accordance with Louisville Gas and Electric Company's Power Supply System Agreement with Kentucky Utilities 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 $867,488.

Schedule Page: 397 Line No.: 3 Column: b

The amount reflects transactions recorded in accordance with Louisville Gas and Electric Company's Power Supply System Agreement with Kentucky Utilities 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 $13,410,416. These amounts do not include $73 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 Louisville Gas and Electric Company's Power Supply System Agreement with Kentucky Utilities 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 $20,306,158. These amounts do not include $73 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

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The amount reflects transactions recorded in accordance with Louisville Gas and Electric Company's Power Supply System Agreement with Kentucky Utilities 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 $26,971,822. These amounts do not include $73 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 Louisville Gas and Electric Company's Power Supply System Agreement with Kentucky Utilities 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 $43,900,069. These amounts do not include $73 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	2,175,153	MWH	181,440	3,278,360	MWH	361,847
2	Reactive Supply and Voltage	2,175,153	MWH	163,915	3,278,360	MWH	319,404
3	Regulation and Frequency Response				3,278,360	MWH	124,510
4	Energy Imbalance						
5	Operating Reserve - Spinning				3,278,360	MWH	192,992
6	Operating Reserve - Supplement				3,278,360	MWH	192,992
7	Other			7,730			
8	Total (Lines 1 thru 7)	4,350,306		353,085	16,391,800		1,191,745

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:	$ 7,632
MISO Schedule 26:	98
	$ 7,730

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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	2,172	12	19	1,811	222	139			
2	February	2,092	11	8	1,725	228	139			
3	March	1,944	10	20	1,574	185	139		47	
4	Total for Quarter 1	6,208			5,110	635	417		47	
5	April	1,669	1	7	1,419	48	139		63	
6	May	2,828	31	16	2,454	72	139		163	
7	June	2,705	8	16	2,490	76	139			
8	Total for Quarter 2	7,202			6,363	196	417		226	
9	July	2,876	11	16	2,654	83	139			
10	August	2,854	2	16	2,623	76	139		16	
11	September	2,888	1	16	2,577	78	139		94	
12	Total for Quarter 3	8,618			7,854	237	417		110	
13	October	1,895	7	17	1,612	46	139		98	
14	November	1,740	18	8	1,488	50	139		63	
15	December	1,782	12	8	1,587	56	139			
16	Total for Quarter 4	5,417			4,687	152	417		161	
17	Total Year to Date/Year	27,445			24,014	1,220	1,668		544	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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)	11,641,054
3	Steam	15,290,896			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	208,895			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,185,682
7	Other	174,613			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	1,571
9	Net Generation (Enter Total of lines 3 through 8)	15,674,404	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	15,194
10	Purchases	1,943,401	27	Total Energy Losses	747,353
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	17,590,854
12	Received	13,434			
13	Delivered	79,453			
14	Net Exchanges (Line 12 minus line 13)	-66,019			
15	Transmission For Other (Wheeling)				
16	Received	3,278,360			
17	Delivered	3,239,292			
18	Net Transmission for Other (Line 16 minus line 17)	39,068			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	17,590,854			

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:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	1,737,045	665,389	1,811	12	1900
30	February	1,398,653	490,428	1,804	10	800
31	March	1,456,331	515,231	1,574	10	2000
32	April	1,252,096	413,103	1,591	10	2000
33	May	1,350,793	337,177	2,457	31	1700
34	June	1,429,041	225,837	2,499	9	1500
35	July	1,708,530	262,859	2,704	12	1400
36	August	1,585,813	263,960	2,623	2	1600
37	September	1,441,886	475,777	2,593	2	1500
38	October	1,370,259	504,121	1,612	7	1700
39	November	1,294,263	447,540	1,577	29	2000
40	December	1,566,144	584,260	1,588	7	1900
41	TOTAL	17,590,854	5,185,682			

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Name of Respondent Louisville Gas and Electric 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: 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 1,845,182 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 1,492,000 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 1,554,047 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 1,343,131 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 1,440,784 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 1,535,564 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 1,813,670 MWH.

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 1,683,620 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 1,542,526 MWH.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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: *Mill Creek* (b)	Plant Name: *Cane Run* (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	1972	1954
4	Year Last Unit was Installed	1982	1969
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1717.00	645.00
6	Net Peak Demand on Plant - MW (60 minutes)	1595	578
7	Plant Hours Connected to Load	7115	7858
8	Net Continuous Plant Capability (Megawatts)	1482	563
9	When Not Limited by Condenser Water	1482	563
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	231	124
12	Net Generation, Exclusive of Plant Use - KWh	9063685000	3222159000
13	Cost of Plant: Land and Land Rights	1546851	1184107
14	Structures and Improvements	128983725	52161054
15	Equipment Costs	956492252	283621621
16	Asset Retirement Costs	9680162	14071865
17	Total Cost	1096702990	351038647
18	Cost per KW of Installed Capacity (line 17/5) Including	638.7321	544.2460
19	Production Expenses: Oper, Supv, & Engr	1146672	427574
20	Fuel	199406857	73107859
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	13761247	19915985
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	59619	62858
26	Misc Steam (or Nuclear) Power Expenses	8275728	5956521
27	Rents	72300	9350
28	Allowances	531	76386
29	Maintenance Supervision and Engineering	1067793	1853165
30	Maintenance of Structures	981486	489686
31	Maintenance of Boiler (or reactor) Plant	22536488	8831893
32	Maintenance of Electric Plant	6650516	1727004
33	Maintenance of Misc Steam (or Nuclear) Plant	645740	852105
34	Total Production Expenses	254604977	113310386
35	Expenses per Net KWh	0.0281	0.0352

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Gas		Coal	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	tons	mcf		tons	mcf	
38	Quantity (Units) of Fuel Burned	4221111	465630	0	1563823	184433	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11448	1025	0	11097	1025	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	45.510	9.819	0.000	46.370	13.841	0.000
41	Average Cost of Fuel per Unit Burned	46.157	9.819	0.000	45.117	13.841	0.000
42	Average Cost of Fuel Burned per Million BTU	2.016	9.579	0.000	2.033	13.503	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.021	0.000	0.000	0.022	0.000	0.000
44	Average BTU per KWh Net Generation	10663.000	0.000	0.000	10772.000	0.000	0.000

Name of Respondent Louisville Gas and Electric 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

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: *Trimble County* (d)	Plant Name: *Cane Run CT* (e)	Plant Name: *Paddy's Run CT* (f)	Line No.
Steam	Combustion Turbine	Combustion Turbine	1
Conventional	Conventional	Conventional	2
1990	1968	1968	3
1990	1968	2001	4
725.00	16.00	143.00	5
518	14	102	6
6610	18	95	7
660	14	134	8
660	14	134	9
0	0	0	10
150	0	0	11
4089124000	198000	16487000	12
3562369	0	0	13
141592010	211518	2222812	14
558810283	3345793	37857268	15
4046240	0	0	16
708010902	3557311	40080080	17
976.5668	222.3319	280.2803	18
829517	0	0	19
96893081	0	0	20
0	0	0	21
3062588	0	0	22
0	0	0	23
-28867	0	0	24
743979	46020	1598602	25
4122030	0	0	26
9931	0	6968	27
44	0	0	28
491238	0	6314	29
734161	13042	15982	30
13267792	0	0	31
1384786	46909	810110	32
416792	0	0	33
121927072	105971	2437976	34
0.0298	0.5352	0.1479	35

(d)			(e)			(f)			Line No.
Coal	Oil		Gas	Oil		Gas			36
tons	barrels		mcf	barrels		mcf			37
1877930	23071	0	4131	4	0	188060	0	0	38
11312	3333	0	4234	3381	0	1025	0	0	39
49.390	95.206	0.000	11.091	50.522	0.000	8.465	0.000	0.000	40
36.685	95.206	0.000	11.091	50.522	0.000	8.465	0.000	0.000	41
1.621	16.191	0.000	10.821	8.470	0.000	8.259	0.000	0.000	42
0.017	0.000	0.000	0.231	0.000	0.000	0.097	0.000	0.000	43
10390.000	0.000	0.000	21384.000	0.000	0.000	11692.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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: *Zorn CT* (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)	Conventional			Conventional		
3	Year Originally Constructed	1969			1999		
4	Year Last Unit was Installed	1969			2001		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	18.00			200.00		
6	Net Peak Demand on Plant - MW (60 minutes)	9			134		
7	Plant Hours Connected to Load	4			165		
8	Net Continuous Plant Capability (Megawatts)	16			199		
9	When Not Limited by Condenser Water	16			199		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	-73000			26463000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	8241			1108873		
15	Equipment Costs	1904786			70501565		
16	Asset Retirement Costs	38429			0		
17	Total Cost	1951456			71610438		
18	Cost per KW of Installed Capacity (line 17/5) Including	108.4142			358.0522		
19	Production Expenses: Oper, Supv, & Engr	0			43251		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			11906		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	19208			2109109		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			11314		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			22005		
30	Maintenance of Structures	0			71142		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	18888			319079		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	38096			2587806		
35	Expenses per Net KWh	-0.5219			0.0978		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	mcf			mcf	barrels	
38	Quantity (Units) of Fuel Burned	831	0	0	345080	3696	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1024	0	0	1025	3333	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5.689	0.000	0.000	5.017	98.373	0.000
41	Average Cost of Fuel per Unit Burned	5.689	0.000	0.000	5.017	98.373	0.000
42	Average Cost of Fuel Burned per Million BTU	5.555	0.000	0.000	4.895	16.731	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	-0.065	0.000	0.000	0.070	0.218	0.000
44	Average BTU per KWh Net Generation	-11658.000	0.000	0.000	14263.000	13052.000	0.000

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Louisville Gas and Electric 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: *Trimble County CT* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Combustion Turbine			1
Conventional			2
2002			3
2002			4
410.00	0.00	0.00	5
320	0	0	6
616	0	0	7
363	0	0	8
363	0	0	9
0	0	0	10
0	0	0	11
131538000	0	0	12
8133	0	0	13
11452996	0	0	14
109122525	0	0	15
0	0	0	16
120583654	0	0	17
294.1065	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
147369	0	0	22
0	0	0	23
0	0	0	24
13628359	0	0	25
0	0	0	26
3032	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
238926	0	0	32
0	0	0	33
14017686	0	0	34
0.1066	0.0000	0.0000	35

									Line No.
Gas									36
mcf									37
1554569	0	0	0	0	0	0	0	0	38
1025	0	0	0	0	0	0	0	0	39
7.524	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
7.524	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
7.340	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.089	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
12114.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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Schedule Page: 402 Line No.: -1 Column: d

Partnership Expenses included in column d:

Line 19	Production Expenses: Oper, Supv, & Engr	$ (207,380)
Line 20	Fuel	(25,805,513)
Line 22	Steam Expenses	(791,728)
Line 25	Electric Expenses	(185,995)
Line 26	Misc Steam Power Expenses	(1,030,509)
Line 27	Rents	(2,483)
Line 28	Allowances	(11)
Line 29	Maintenance Supervision and Engineering	(122,810)
Line 30	Maintenance of Structures	(183,541)
Line 31	Maintenance of Boiler Plant	(3,316,950)
Line 32	Maintenance of Electric Plant	(346,197)
Line 33	Maintenance of Misc Steam Plant	(104,199)
Line 34	Total Production Expenses	$ (32,097,316)

Schedule Page: 402 Line No.: 1 Column: d

See note 10 of Notes to the Financial Statements related to Jointly Owned Electric Utility Plant.

Schedule Page: 402 Line No.: 5 Column: f

The Nameplate Rating for Paddy's Run represents 100% ownership of unit 11, a 16 MW unit, and unit 12, a 33 MW unit, and 53% ownership of unit 13, a 178 MW unit, for LG&E. The remaining percentage of unit 13 is owned by KU.

Schedule Page: 402 Line No.: 11 Column: e

Employees at the Cane Run Plant include those assigned to the steam plant and the Cane Run CT site and are reflected in the Cane Run Steam Plant statistics.

Schedule Page: 402 Line No.: 11 Column: f

No production/operation employees are directly assigned to Paddy's Run turbines. Employees from the Cane Run Plant operate and maintain the Paddy's Run turbines.

Schedule Page: 402.1 Line No.: -1 Column: b

Zorn station is peak load only and is automatically operated.

Schedule Page: 402.1 Line No.: 5 Column: c

The Nameplate Rating for Brown CT represents 53% ownership of unit 5, a 123 MW unit, and 38% ownership of units 6 and 7, which are 177 MW each, for LG&E. The remaining percentages of units 5, 6 and 7 are owned by KU.

Schedule Page: 402.1 Line No.: 5 Column: d

The Nameplate Rating for Trimble County CT represents 29% ownership of units 5 and 6, and 37% ownership of units 7, 8, 9 and 10 for LG&E. The remaining percentages for units 5, 6, 7, 8, 9 and 10 are owned by KU. 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 the Zorn station. Employees from the Cane Run Plant maintain the Zorn station.

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

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
Louisville Gas and Electric 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. 289 Plant Name: Ohio Falls (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1928	
4	Year Last Unit was Installed	1928	
5	Total installed cap (Gen name plate Rating in MW)	85.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	66	0
7	Plant Hours Connect to Load	5,537	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	34	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	6	0
12	Net Generation, Exclusive of Plant Use - Kwh	208,895,000	0
13	Cost of Plant		
14	Land and Land Rights	6	0
15	Structures and Improvements	4,963,376	0
16	Reservoirs, Dams, and Waterways	11,690,252	0
17	Equipment Costs	25,765,296	0
18	Roads, Railroads, and Bridges	29,931	0
19	Asset Retirement Costs	103,529	0
20	TOTAL cost (Total of 14 thru 19)	42,552,390	0
21	Cost per KW of Installed Capacity (line 20 / 5)	500.6164	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	107,576	0
24	Water for Power	38,653	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	264,529	0
27	Misc Hydraulic Power Generation Expenses	126,221	0
28	Rents	379,818	0
29	Maintenance Supervision and Engineering	12,927	0
30	Maintenance of Structures	370,849	0
31	Maintenance of Reservoirs, Dams, and Waterways	74,086	0
32	Maintenance of Electric Plant	277,516	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	1,652,175	0
35	Expenses per net KWh	0.0079	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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
Louisville Gas and Electric 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)	On Structures of Another Line (g)	Number Of Circuits (h)
1	Mill Creek Sub	Paddy's West Sub	345.00	345.00	ST	14.54		2
2	Paddy's West Sub	Northside Sub	345.00	345.00	ST, SP	14.52		1
3	Trimble County Sub	Clifty Creek Sub	345.00	345.00	ST,WP	12.35		2
4	Blue Lick Sub	Middletown Sub	345.00	345.00	ST	0.12	19.22	1
5	Buckner	Wises Landing	345.00	345.00	ST,SP	0.32	13.11	1
6	Middletown	Buckner	345.00	345.00	ST,SP	0.23	13.89	1
7	Middletown Sub	Trimble County Sub	345.00	345.00	ST	27.96		1
8	Mill Creek Sub	Blue Lick Sub	345.00	345.00	ST	0.24	11.80	1
9	Mill Creek Sub	Middletown Sub	345.00	345.00	ST	31.36		1
10	Paddy's Run Sub	T.V.A. Tower	161.00	161.00	ST	66.16	50.25	2
11	Appl Park Switching Station	Middletown Sub	138.00	138.00	ST	0.08	12.56	1
12	Appl Park Switching Station	Ethel Sub	138.00	138.00	WP, ST	1.95		1
13	Ashbottom Sub	Appl Park Switching Station	138.00	138.00	ST	4.61	1.30	1
14	Grade Lane	Fern Valley Sub	138.00	138.00	ST,SP	2.79		1
15	Ashbottom	Grade Lane	138.00	138.00	ST,SP	0.92		1
16	Ashbottom Sub	Manslick Sub	138.00	138.00	WP, ST	3.43		1
17	Ashby Sub	Pleasure Ridge Park Sub	138.00	138.00	WP,SP,CP	2.82		1
18	Beargrass Sub	Lyndon South Sub	138.00	138.00	ST	0.10	7.33	1
19	Beargrass Sub	Middletown Sub	138.00	138.00	ST	9.06	5.53	2
20	Beargrass Sub	Northside Sub	138.00	138.00	ST,SP	6.37		1
21	Beargrass Sub	Northside Sub	138.00	138.00	ST	0.23	6.11	1
22	Breckenridge Sub	Hurstbourne Sub	138.00	138.00	WP, SP,CP	3.89	0.17	1
23	Campground	Cane Run Switching Station	138.00	138.00	ST	3.08	3.29	2
24	Canal Sub	Waterside West	138.00	138.00	ST	0.23	0.87	1
25	Cane Run Switching Station	Ashbottom Sub	138.00	138.00	ST	9.64	7.87	3
26	Cane Run	Cane Run Switching Station	138.00	138.00	ST,WP	5.10		2
27	Cane Run	Cane Run Switching Station	138.00	138.00	ST ,WP	0.46	2.23	2
28	Cane Run	Cane Run Switching Station	138.00	138.00	ST	2.56		1
29	Cane Run	Cane Run Switching Station	138.00	138.00	ST	0.26	2.33	1
30	Cane Run Switching Station	International	138.00	138.00	ST,SP,WP	1.34	1.48	1
31	Centerfield Sub	Trimble County Sub	138.00	138.00	WP, ST	15.08	0.67	1
32	Dixie Sub	Algonquin Sub	138.00	138.00	WP,SP	0.80		1
33	Ethel Sub	Breckenridge Sub	138.00	138.00	WP, ST,SP	3.90		1
34	Fern Valley Sub	Okolona Sub	138.00	138.00	WP, SP	1.40		1
35	Fern Valley Sub	Watterson Sub	138.00	138.00	ST	3.92	1.36	1
36					TOTAL	675.53	240.83	85

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)	
954 mcm	113,337	2,619,695	2,733,032					1
1024.5 mcm	102,753	4,109,451	4,212,204					2
954 mcm		2,746,513	2,746,513					3
954 mcm		807,000	807,000					4
954 mcm		2,990,335	2,990,335					5
954 mcm		2,660,313	2,660,313					6
954mcm	479,907	7,450,485	7,930,392					7
954 mcm		445,553	445,553					8
954 mcm	314,954	4,035,923	4,350,877					9
500 mcm	98,666	2,425,288	2,523,954					10
795 mcm	102,525	928,157	1,030,682					11
795 mcm	862	331,271	332,133					12
795 mcm	42,502	490,157	532,659					13
795 mcm		300,055	300,055					14
795 mcm		186,861	186,861					15
795 mcm		420,671	420,671					16
1272 mcm		1,021,519	1,021,519					17
795 mcm		121,582	121,582					18
795 mcm	159,406	1,282,428	1,441,834					19
1024.5 mcm	67,983	2,284,633	2,352,616					20
1024.5 mcm	6,427	527,124	533,551					21
1272 mcm	15,419	1,425,739	1,441,158					22
795 mcm	8,216	227,384	235,600					23
795 mcm		326,677	326,677					24
795 mcm	38,205	1,212,277	1,250,482					25
795 mcm	18,788	408,209	426,997					26
795 mcm		191,740	191,740					27
954 mcm		156,147	156,147					28
954 mcm		112,910	112,910					29
795 mcm		574,206	574,206					30
795 mcm	85,784	1,212,183	1,297,967					31
795 mcm	1,446	331,415	332,861					32
1272 mcm	27,072	1,179,516	1,206,588					33
1272 mcm		418,533	418,533					34
795 mcm	2,054	57,683	59,737					35
	7,813,666	151,908,822	159,722,488	117,265	1,307,208	23,716	1,448,189	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Hurstbourne Sub	Bluegrass Sub	138.00	138.00	SP,WP	2.02		1
2	Knob Creek Sub	Tip Top Sub	138.00	138.00	WP,ST,CP	11.79		1
3	Lyndon South Sub	Middletown Sub	138.00	138.00	ST,SP	5.58		1
4	Magazine Sub	Hancock Sub	138.00	138.00	SP, WP	2.34		1
5	Magazine Sub	Waterside West	138.00	138.00	ST, SP, WP	3.38		1
6	Manslick Sub	Mill Creek Sub	138.00	138.00	WP, ST	10.52		1
7	Middletown Sub	Centerfield Sub	138.00	138.00	WP, ST	12.26		1
8	Mill Creek Sub	Ashby Sub	138.00	138.00	WP, SP	5.56		1
9	Mill Creek Sub	Knob Creek Sub	138.00	138.00	WP, ST	2.80	3.59	1
10	Mill Creek Sub	Kosmosdale Prim. Meter Stn.	138.00	138.00	WP, ST	1.27	0.44	2
11	Mud Lane Sub	Blue Lick Sub	138.00	138.00	SP,WP	5.45		1
12	Okolona Sub	Mud Lane Sub	138.00	138.00	WP, ST	3.85	0.18	1
13	Paddy's Run Sub	Campground	138.00	138.00	ST	0.45		1
14	Paddy's Run Sub	Dixie Sub	138.00	138.00	WP,SP	3.58		1
15	Paddy's Run Sub	Ohio Falls Sub	138.00	138.00	ST	12.41	0.39	3
16	Paddy's Run Sub	Paddy's West Sub	138.00	138.00	ST	0.69	0.12	2
17	Plainview Sub	Hurstbourne Sub	138.00	138.00	WP, SP	2.18		1
18	Paddy's West Sub	PSI Connection Gallagher	138.00	138.00	SP	0.42		1
19	Northside Sub	Clifty Creek Sub	138.00	138.00	ST,WP	32.54		1
20	Northside Sub	Tower No. 43 at P.S.I.						
21		Connection	138.00	138.00	ST	0.19	0.04	1
22	Clifty Creek Sub	Tower No.220 Connection						
23		with CG&E Co.	138.00	138.00	ST	4.25	2.50	1
24	Watterson Sub	Middletown Sub	138.00	138.00	ST,WP	7.20	0.22	1
25	Tip Top Sub	Cloverport Sub	138.00	138.00	WP,SP,ST	32.81	2.74	
26	Waterside West	Beargrass Sub	138.00	138.00	ST,SP	2.08		2
27	Waterside West	Beargrass Sub	138.00	138.00	SP	0.25	1.81	1
28	Mill Creek Sub	Cane Run Sub	138.00	138.00	ST,SP	1.19	10.12	1
29	Mill Creek	East Fort Knox	345.00	345.00	HF,ST	6.89		1
30	Middletown	Old Henry	138.00	138.00	ST	4.03		1
31	Old Henry	Collins	138.00	138.00	SP	3.22	0.29	1
32	Trimble County	Speed	345.00	345.00	ST,SP	2.48		1
33	Trimble County	Ghent	345.00	345.00	ST,SP	0.04	2.44	1
34	Overhead Lines under							
35	132KV		69.00	69.00	WP,ST	233.18	54.58	
36					TOTAL	675.53	240.83	85

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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)	
1272 mcm	37,300	1,164,786	1,202,086					1
636 mcm	7,955	789,381	797,336					2
795 mcm	35,941	537,648	573,589					3
1272 mcm		1,432,718	1,432,718					4
795 mcm	2,600	1,125,652	1,128,252					5
636 mcm	16,570	1,588,177	1,604,747					6
795 mcm	42,761	815,255	858,016					7
1272 mcm	528	1,914,207	1,914,735					8
636 mcm	10,855	380,551	391,406					9
840.2 mcm		336,699	336,699					10
840.2 mcm	46,432	2,601,255	2,647,687					11
1272 mcm	79,825	1,150,040	1,229,865					12
795 mcm	1,455	64,918	66,373					13
795 mcm	27,351	805,850	833,201					14
300 mcm	81,226	977,581	1,058,807					15
954 mcm	2,763	421,996	424,759					16
1272 mcm	3,591	734,061	737,652					17
954 mcm		219,011	219,011					18
336.4 mcm	73,852	1,363,998	1,437,850					19
								20
954 mcm		45,884	45,884					21
								22
336.4 mcm	22,743	191,394	214,137					23
840.2 mcm		361,979	361,979					24
397.5 mcm	48,020	1,738,144	1,786,164					25
795 mcm	17,950	443,294	461,244					26
795 mcm		258,350	258,350					27
954 mcm	20,979	683,637	704,616					28
954mcm		13,349,277	13,349,277					29
954mcm		3,440,995	3,440,995					30
954 mcm		426,399	426,399					31
954 mcm		8,685,594	8,685,594					32
954mcm		8,685,594	8,685,594					33
								34
Various	5,546,663	41,708,450	47,255,113					35
	7,813,666	151,908,822	159,722,488	117,265	1,307,208	23,716	1,448,189	36

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	Ashbottom Sub	Grade Lane Sub	138.00	138.00	Undg. (26)	0.58		1
2	Waterside West	Canal Sub	138.00	138.00	Undg. (26)	0.75		1
3	Magazine Sub	Hancock Sub	138.00	138.00	Undg. (26)	0.09		1
4	Magazine Sub	Waterside West	138.00	138.00	Undg. (26)	0.75		1
5	Waterside West	Beargrass Sub	138.00	138.00	Undg. (26)	0.93		1
6	Waterside West	Beargrass Sub	138.00	138.00	Undg. (26)	0.93		1
7	Underground Lines under							
8	132KV		69.00	69.00	Undg. (26)	2.78		
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	Exp Applicable to All Lines							
36					TOTAL	675.53	240.83	85

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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 (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1500 Kcmil cu		1,042,460	1,042,460					1
1750 mcm ho		25,558	25,558					2
1750 mcm cu		305,807	305,807					3
1500 mcm ho		25,441	25,441					4
1500 mcm cu		1,705,258	1,705,258					5
1500 mcm ho		1,465,974	1,465,974					6
								7
Various		2,875,916	2,875,916					8
								9
								10
								11
								12
								13
								14
								15
								16
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								29
								30
								31
								32
								33
				117,265	1,307,208	23,716	1,448,189	34
								35
	7,813,666	151,908,822	159,722,488	117,265	1,307,208	23,716	1,448,189	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	Old Henry	Collins 138	3.47	SP	6.00	1	
2							
3							
4							
5							
6							
7							
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41							
42							
43							
44	TOTAL		3.47		6.00	1	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

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.
954mcm			138,000			426,399		426,399	1
									2
									3
									4
									5
									6
									7
									8
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									11
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									41
									42
									43
						426,399		426,399	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	Aiken	Transmission*	69.00		
2	Algonquin	Transmission*	138.00	69.00	13.80
3	Appliance Park	Transmission*	138.00		
4	Ashbottom	Transmission*	138.00	69.00	13.80
5	Beargrass	Transmission*	138.00	69.00	13.80
6	Beargrass Pumping	Transmission*	69.00		
7	Blue Lick, Brooks, Ky	Transmission*	345.00	138.00	
8	Blue Lick, Brooks, Ky	Transmission*	345.00	161.00	
9	Blue Lick, Brooks, Ky	Transmission*	138.00	69.00	13.80
10	Breckinridge	Transmission*	138.00	69.00	13.20
11	Cane Run	Transmission*	138.00	69.00	
12	Canal	Transmission*	136.80	66.00	14.00
13	Cane Run Switching	Transmission*	138.00	69.00	13.80
14	Centerfield	Transmission*	138.00	69.00	13.80
15	Clay	Transmission*	69.00		
16	Clifton	Transmission*	69.00		
17	Cloverport	Transmission*	138.00		
18	Collins	Transmission*	69.00	12.47	
19	Collins	Transmission*	138.00	69.00	
20	Eastwood	Transmission*	69.00		
21	Ethel	Transmission*	138.00	69.00	13.80
22	Farnsley	Transmission*	69.00		
23	Fern Valley	Transmission*	138.00	69.00	13.80
24	Ford	Transmission*	69.00	12.47	
25	Grady	Transmission*	69.00		
26	Hancock	Transmission*	138.00	69.00	13.80
27	Harrods Creek	Transmission*	69.00		
28	Lyndon	Transmission*	69.00		
29	Lyndon South, Lyndon, Ky	Transmission*	138.00	69.00	13.80
30	Madison	Transmission*	69.00		
31	Middletown, Middletown, Ky	Transmission*	345.00	138.00	
32	Middletown, Middletown, Ky	Transmission*	138.00	69.00	
33	Middletown, Middletown, Ky	Transmission*	138.00	69.00	13.80
34	Mill Creek, Kosmosdale, Ky	Transmission*	345.00	138.00	13.80
35	Mill Creek, Kosmosdale, Ky	Transmission*	138.00	69.00	13.80
36	Mill Creek, Kosmosdale, Ky	Transmission*	138.00	69.00	14.00
37	Mud Lane	Transmission*	138.00	69.00	13.80
38	Northside, Jeffersonville, Indiana	Transmission*	345.00	138.00	13.80
39	Ohio Falls	Transmission*	69.00	13.80	
40	Oxmoor	Transmission*	69.00		

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Louisville Gas and Electric 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.
			NONE			1
140	1		NONE			2
			NONE			3
224	2		NONE			4
185	1		NONE			5
			NONE			6
448	1		NONE			7
240	1		NONE			8
112	1		NONE			9
112	1		NONE			10
			NONE			11
93	1		NONE			12
224	2		NONE			13
140	1		NONE			14
			NONE			15
			NONE			16
			NONE			17
			NONE			18
149	1		NONE			19
			NONE			20
140	1		NONE			21
			NONE			22
80	2		NONE			23
			NONE			24
			NONE			25
140	1		NONE			26
			NONE			27
			NONE			28
140	1		NONE			29
			NONE			30
1344	3		NONE			31
150	1		NONE			32
298	2		NONE			33
672	2		NONE			34
40	1		NONE			35
40	1		NONE			36
140	1		NONE			37
448	1		NONE			38
			NONE			39
			NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	Paddy's Run	Transmission*	161.00	138.00	
2	Paddy's Run	Transmission*	138.00	69.00	14.00
3	Paddy's West - Indiana	Transmission*	345.00	138.00	13.80
4	Seminole	Transmission*	69.00		
5	Shivley	Transmission*	69.00		
6	Smyrna	Transmission*	69.00	12.47	
7	Taylor	Transmission*	69.00		
8	Tip Top, Ky	Transmission*	135.00	66.00	14.00
9	Tip Top, Ky	Transmission*	135.00	66.00	37.00
10	Trimble County CT	Transmission*	362.25	18.00	
11	Trimble County	Transmission*	345.00	138.00	
12	Waterside West	Transmission*	138.00	13.80	
13	Waterside Switching Station	Transmission*	138.00		
14	Watterson	Transmission*	138.00	69.00	13.80
15	Worthington	Transmission*	69.00	12.47	
16	Total Transmission		7968.05	2800.48	340.80
17					
18	Aiken	Distribution*	69.00	12.47	
19	Algonquin	Distribution*	69.00	13.80	
20	Ashbottom	Distribution*	138.00	13.80	
21	Ashby	Distribution*	138.00	12.47	
22	Bishop	Distribution*	69.00	12.47	
23	Bluegrass	Distribution*	138.00	12.47	
24	Brandenburg, near Brandenburg, Ky	Distribution*	69.00	12.47	
25	Breckenridge	Distribution*	69.00	13.80	
26	Breckenridge	Distribution*	69.00	12.47	
27	Campground	Distribution*	138.00	13.80	
28	Canal	Distribution*	69.00	13.80	
29	Cane Run	Distribution*	69.00	13.80	
30	Centerfield	Distribution*	138.00	12.47	
31	Clay	Distribution*	69.00	13.80	
32	Clifton	Distribution*	69.00	13.80	
33	Clifton	Distribution*	69.00	12.47	
34	Collins	Distribution*	69.00	12.47	
35	Conestoga	Distribution*	69.00	12.47	
36	Crestwood, Crestwood, Ky	Distribution*	69.00	12.47	
37	Dahila	Distribution*	69.00	12.47	
38	Del Park	Distribution*	69.00	13.80	
39	Dixie	Distribution*	138.00	12.47	
40	Eastwood West	Distribution*	69.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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)	
200	1		NONE			1
187	1		NONE			2
448	1		NONE			3
			NONE			4
			NONE			5
			NONE			6
			NONE			7
34	1		NONE			8
45	1		NONE			9
			NONE			10
224	1		NONE			11
			NONE			12
			NONE			13
152	2		NONE			14
			NONE			15
6989	38					16
						17
73	2		NONE			18
101	3		Ground Transformer	4	12	19
95	2		Ground Transformer	2	10	20
56	2		NONE			21
56	2		NONE			22
90	2		NONE			23
10	1		NONE			24
40	2		Ground Transformer	2	5	25
84	3		NONE			26
45	1		Ground Transformer	1	5	27
60	2		Ground Transformer	2	8	28
120	2		Ground Transformer	9	60	29
45	1		NONE			30
50	2		Ground Transformer	2	10	31
40	2		Ground Transformer	2	9	32
56	2		NONE			33
56	2		NONE			34
28	1		NONE			35
56	2		NONE			36
56	2		NONE			37
45	1		Ground Transformer	1	5	38
45	1		NONE			39
45	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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)	
25	1		Ground Transformer	1	4	1
56	2		NONE			2
73	2		NONE			3
56	2		NONE			4
78	2		Ground Transformer	2	9	5
101	3		NONE			6
45	1		Ground Transformer	1	5	7
90	2		NONE			8
73	2		NONE			9
202	3		Ground Transformer	2	10	10
66	3		Ground Transformer	2	9	11
45	1		NONE			12
28	1		NONE			13
56	2		NONE			14
11	2		NONE			15
45	1		Ground Transformer	1	5	16
34	1		NONE			17
45	1		Ground Transformer	1	5	18
34	1		NONE			19
90	2		NONE			20
90	2		NONE			21
73	2		NONE			22
56	2		NONE			23
30	1		NONE			24
45	1		NONE			25
28	1		NONE			26
28	1		NONE			27
12	2		NONE			28
134	3		Ground Transformer	2	10	29
15	2		Ground Transformer	3	15	30
111	3		NONE			31
45	1		NONE			32
28	1		Ground Transformer	2	19	33
90	2		NONE			34
84	3		NONE			35
45	1		NONE			36
45	1		NONE			37
56	2		NONE			38
335	6		Ground Transformer	5	70	39
14	2		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	Ethel	Distribution*	69.00	13.80	
2	Ethel	Distribution*	69.00	12.47	
3	Fairmount	Distribution*	69.00	12.47	
4	Farnsley Shively, Ky	Distribution*	69.00	12.47	
5	Fern Valley	Distribution*	138.00	13.80	
6	Fern Valley	Distribution*	138.00	12.47	
7	Floyd	Distribution*	69.00	13.80	
8	Ford Truck Plant	Distribution*	69.00	12.47	
9	Frey's Hill	Distribution*	69.00	12.47	
10	Grade Lane	Distribution*	138.00	13.80	
11	Grady	Distribution*	69.00	13.80	
12	Hancock	Distribution*	138.00	12.47	
13	Harmony Landing, near Goshen , Ky	Distribution*	69.00	12.47	
14	Harrod's Creek	Distribution*	69.00	12.47	
15	Herman - Class B	Distribution*	13.80	4.16	
16	Highland #1	Distribution*	69.00	12.47	
17	Highland	Distribution*	69.00	13.80	
18	Hillcrest	Distribution*	69.00	12.47	
19	Hillcrest	Distribution*	69.00	13.80	
20	Hurstbourne, Jeffersontown, Ky	Distribution*	138.00	12.47	
21	International	Distribution*	138.00	12.47	
22	Jeffersontown	Distribution*	69.00	12.47	
23	Kenwood	Distribution*	69.00	12.47	
24	Knob Creek, near Shepherdsville, Ky	Distribution*	138.00	34.50	14.00
25	Locust	Distribution*	69.00	12.47	
26	Lyndon, Ky	Distribution*	69.00	12.47	
27	Lyndon South	Distribution*	69.00	12.47	
28	Lynn	Distribution*	13.80	4.16	
29	Madison	Distribution*	69.00	13.80	
30	Magazine	Distribution*	13.80	4.16	
31	Magazine	Distribution*	69.00	13.80	
32	Manslick	Distribution*	138.00	12.47	
33	Mill Creek	Distribution*	138.00	12.47	
34	Mud Lane	Distribution*	138.00	12.47	
35	Nachand	Distribution*	69.00	12.47	
36	Okolona	Distribution*	138.00	12.47	
37	Old Henry	Distribution*	138.00	12.47	
38	Oxmoor	Distribution*	69.00	12.47	
39	Paddy's Run	Distribution*	138.00	13.80	
40	Pirtle	Distribution*	13.80	4.16	

Name of Respondent Louisville Gas and Electric 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	Plainview	Distribution*	138.00	12.47	
2	Pleasure Ridge Park	Distribution*	138.00	12.47	
3	Seminole	Distribution*	69.00	13.80	
4	Seminole	Distribution*	69.00	12.47	
5	Seminole	Distribution*	69.00	13.80	
6	Seventh Street	Distribution*	13.80	4.16	
7	Shepherdsville, Ky	Distribution*	69.00	12.47	
8	Shively	Distribution*	69.00	12.47	
9	Shively	Distribution*	69.00	13.80	
10	Skylight, Ky	Distribution*	69.00	12.47	
11	Smyrna	Distribution*	69.00	12.47	
12	South Park	Distribution*	69.00	12.47	
13	South Park	Distribution*	69.00	34.50	14.00
14	Southern	Distribution*	13.80	4.16	
15	Stewart	Distribution*	69.00	12.47	
16	Taylor	Distribution*	69.00	12.47	
17	Terry	Distribution*	69.00	12.47	
18	Tip Top	Distribution*	138.00	34.50	28.00
19	Waterside West	DIstribution*	138.00	13.80	
20	Watterson	Distribution*	138.00	12.47	
21	West Point	Distribution*	34.50	12.47	
22	Western	Distribution*	13.80	4.16	
23	Worthington	Distribution*	69.00	12.47	
24	WHAS	Distribution*	69.00	12.47	
25	21 Stations Less Than 10,000 Kva				
26	Total Distribution		7238.10	1123.40	56.00
27					
28					
29					
30					
31					
32					
33	Summary				
34	Transmission 45				
35	Distribution 97				
36	Total 142				
37					
38	(1) Located in or near Louisville except as noted.				
39					
40	* Unattended				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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)	
45	1		NONE			1
45	1		NONE			2
95	3		Ground Transformer	4	19	3
45	1		NONE			4
134	2		NONE			5
14	2		NONE			6
21	2		NONE			7
45	1		Ground Transformer	1	5	8
25	1		NONE			9
10	1		NONE			10
56	2		NONE			11
28	1		NONE			12
10	1		NONE			13
14	2		NONE			14
62	3		NONE			15
84	3		NONE			16
73	2		NONE			17
101	2		NONE			18
200	4		NONE			19
73	2		NONE			20
11	1		NONE			21
14	2		NONE			22
45	1		NONE			23
20	2		NONE			24
117	29		NONE			25
5356	187			52	309	26
						27
						28
						29
						30
						31
						32
						33
6989	38	5				34
5356	187			52	309	35
12345	225	5		52	309	36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric 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	Kentucky Utilities Company	see footnote	14,115,961
3	Direct-Indirect Labor	Kentucky Utilities Company	see footnote	1,893,915
4	Equipment and Facilities	Kentucky Utilities Company	see footnote	342,918
5	Office and Administrative Services	Kentucky Utilities Company	see footnote	1,148,514
6	Materials and Fuels	Kentucky Utilities Company	see footnote	1,952,080
7	Outside Services	Kentucky Utilities Company	see footnote	547,014
8				
9	Capital Expenditures	LG&E and KU Services Company	see footnote	19,297,863
10	Direct-Indirect Labor	LG&E and KU Services Company	see footnote	83,383,040
11	Equipment and Facilities	LG&E and KU Services Company	see footnote	8,452,060
12	Office and Administrative Services	LG&E and KU Services Company	see footnote	7,358,739
13	Materials and Fuels	LG&E and KU Services Company	see footnote	1,552,371
14	Outside Services	LG&E and KU Services Company	see footnote	13,480,613
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Capital Expenditures	Kentucky Utilities Company	see footnote	9,109,219
22	Direct-Indirect Labor	Kentucky Utilities Company	see footnote	8,063,903
23	Equipment and Facilities	Kentucky Utilities Company	see footnote	2,921,528
24	Office and Administrative Services	Kentucky Utilities Company	see footnote	51,631
25	Materials and Fuels	Kentucky Utilities Company	see footnote	64,345,076
26	Outside Services	Kentucky Utilities Company	see footnote	1,557,152
27				
28	Capital Expenditures	LG&E and KU Services Company	see footnote	1,436
29	Direct-Indirect Labor	LG&E and KU Services Company	see footnote	1,388,697
30		.		
31	Capital Expenditures	LG&E and KU Capital LLC	see footnote	15
32	Direct-Indirect Labor	LG&E and KU Capital LLC	see footnote	97,940
33	Equipment and Facilities	LG&E and KU Capital LLC	see footnote	341,074
34	Office and Administrative Services	LG&E and KU Capital LLC	see footnote	448
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, 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.: 4 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.: 5 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.: 6 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.: 7 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.: 9 Column: c
Accounts charged include: 107 and 108

Schedule Page: 429 Line No.: 10 Column: c
Accounts charged include: 163, 183, 184, 186, 242, 408, 426, 500-502, 505, 506, 510, 512-514, 541, 544, 556, 560-563, 566, 570, 571, 573, 580, 581, 583, 584, 586, 588, 590, 592, 593, 598, 818, 851, 856, 871, 874, 875, 877, 880, 891, 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, 512, 513, 556, 560, 561, 563, 566, 570, 580, 586, 588, 593, 818, 874, 875, 877, 880, 887, 901-903, 905, 907-910, 921, 930 and 935

Schedule Page: 429 Line No.: 12 Column: c
Accounts charged include: 181-184, 186, 232, 426, 500-502, 506, 510, 512, 513, 539, 541, 556, 560-563, 566, 570, 571, 580, 582, 583, 586, 588, 590, 592-594, 598, 807, 818, 856, 874, 875, 877, 880, 887, 901-903, 905, 907-910, 913, 920, 921, 925, 926, 930 and 935

Schedule Page: 429 Line No.: 13 Column: c
Accounts charged include: 151, 163, 165, 184, 186, 236, 426, 500-502, 506, 510-513, 544, 556, 560, 561, 566, 570, 580, 582, 588, 592, 593, 595, 818, 834, 874, 880, 887, 894, 901, 903, 905, 907-909, 921, 923, 930 and 935

Schedule Page: 429 Line No.: 14 Column: c
Accounts charged include: 165, 182-184, 186, 232, 242, 426, 456, 500-502, 506, 510, 512, 513, 556, 560-562, 566, 570, 580, 582, 583, 586, 588, 590, 592, 593, 595, 598, 817, 818, 821, 832-834, 851, 863, 874, 880, 887, 901, 903, 905, 908-910, 921, 923, 925, 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, 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.: 23 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.: 24 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.: 25 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.: 26 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.: 28 Column: c

Accounts charged include: 107

Schedule Page: 429 Line No.: 29 Column: c

Accounts charged include: 143, 146, 184, 219, 228, 232 and 236

Schedule Page: 429 Line No.: 31 Column: c

Accounts charged include: 107

Schedule Page: 429 Line No.: 32 Column: c

Accounts charged include: 228, 408, 426, 920, 925, 926 and 935

Schedule Page: 429 Line No.: 33 Column: c

Accounts charged include: 426, 921, 931 and 935

Schedule Page: 429 Line No.: 34 Column: c

Accounts charged include: 921

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 LG&E and KU. 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. LG&E, KU and Servco). For the second step, the ratio of Servco to total employees will then be allocated to the other companies (LG&E, KU 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 LG&E and KU. 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 (LG&E, KU 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.

Schedule | Page No.

a PPL company

ANNUAL REPORT

Major Natural Gas Companies

Public Service Commission
of Kentucky

Exact Legal Name of Respondent (Company)	Year/Period of Report
Louisville Gas and Electric Company	End of 2011/Q4

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Principal Payment and Interest Information

	Amount	Yes/No
Amount of Principal Payment During Calendar Year	$0.00	
Is Principal Current?	Y	
Is Interest Current?	Y	

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Services Performed by Independent CPA

	Yes/No	A/C/R
Are your financial statements examined by a Certified Public Accountant?		
Enter Y for Yes or N for No	Y	
If yes, which service is performed?		
Enter an X on each appropriate line		
Audit		X
Compilation		
Review		

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Gas Purchases

Seller	Acct	Gas Purc MCF	Cost of Gas
Gas Purchases	803	32,486,623	$163,298,891.00
Performance Based Ratemaking Incentive (1)	803	0	($1,497,401.00)
Gas Supply Adjustments	803	0	($4,979,506.00)
Wholesale Purchases	803	442,235	$1,771,814.00
Total		32,928,858	$158,593,798.00

Note:
(1) See Note 2 under "Notes to Financial Statements" concerning Performance Based Ratemaking.

Additional Information - Counties

Bullitt, Green, Hardin, Hart, Henry, Jefferson, Larue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Spencer, Trimble, Washington

Revenues, Customers and MCF Sales

	Revenues	MCFs Nat Gas Sold	Customers
Residential (480)	$194,841,842.00	19,058,196	292,779
Commercial and Industrial Sales (481)			
Small (or Commercial)	$71,061,038.00	8,362,025	24,406
Large (Or Industrial)	$7,457,093.00	991,489	286
Other Sales to Public Authorities (482)	$12,019,051.00	1,545,906	1,109
Interdepartmental Sales (484)	$7,246,861.00	730,352	2
Total Sales to Ultimate Customers	$292,625,885.00	30,687,968	318,582
Sales for Resale (483)	$1,910,240.00	442,235	0
Total Natural Gas Service	$294,536,125.00	31,130,203	318,582

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22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Identification (Ref Page: 1)

	Name	Address1	Address2	City	State	Zip	Phone
Exact Legal Name of Respondent							
	Louisville Gas and Electric Company						
Previous Name and Date of change (if name changed during the year)							
Name Address and Phone number of the contact person							
	Eric Raible	220 West Main Street	P.O. Box 32030	Louisville	KY	40232	5026273426
Note File: Attestation and signature via Electronic Filing							

General Information - (1) (Ref Page: 101)

	Name	Address	City	State	Zip
Provide name and title of the Officer having custody of the general corporate books of account	Kent W. Blake, Chief Financial Officer				
Provide Address of Office where the general Corporate books are kept		220 West Main Street	Louisville	KY	40202
Provide the Address of any other offices where other coprorate books are kept if different from where the general corporate books are kept					

General Information (2,3,4) (Ref Page: 101)

	Explain
Provide the name of the State under the laws which respondent is incorporated and date	
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 - July 2, 1913
If at any time during the year the property of respondent was held by a receiver or trustee	
give (a) the 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
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 and gas services in the City of Louisville and adjacent territory in Kentucky.

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22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

General Information - (5) (Ref Page: 101)

	Yes/No	Date
Have you engaged as the principal acountant to audit your financial statements an accountant who is not the principal account for the previous years certified financial statements?	Y	
Enter Y for Yes or N for No	Y	
If yes, Enter the date when such independend accountant was initially engaged		02/23/2011

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Security Holders and Voting Powers - Part 1 (Ref Page: 107)

	Explain	Date	Total
1. Give date of the latest closing of the stock book prior to end of the year, and state the purpose of such closing:	Stock books not closed during the year.		
2. State the total number of votes cast at the latest general meeting prior to end of year for election of directors or the respondent and the number of such votes cast by proxy			
Total:			21,294,223
By Proxy:			21,294,223
3. Give the date and place of such a meeting	Louisville, KY	12/15/2011	
Voting Securities			
Number of votes as of Date:			21,294,223

Security Holders and Voting Powers - Part 2 (Ref Page: 107)

	Name	Address	Total Votes	Common Stock	Preferred Stock	Other
4. Total votes of all voting securities			21,294,223	21,294,223	0	0
5. Total number of all security holders			1	1	0	0
6. Total Votes of Security Holders listed below						
	LG&E and KU Energy LLC	Louisville, KY	21,294,223	21,294,223	0	0

Important Changes During the Year (Ref Page: 108)

	Explain
Give particulars concerning the matters indicated below.	
1. Changes in and important additions to franchise rights:	None.
2. Acquisition of ownership in other companies by reorganization, merger or consolidation with other companies:	None.
3. Purchase or sale of an operating unit or system:	In September 2011, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company("KU") 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. LG&E and KU will jointly acquire the assets as tenants in common, with LG&E and KU having 69% and 31% respective undivided interests. The purchase is subject to receipt of approvals from the Kentucky Public Service Commission, the Virginia State Corporation 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. Important leaseholds (other than leaseholds for natural gas lands) thant have been accquired or given assigned or surrendered:	None of a material nature.
5. Important extension or reduction of transmission or distribution system:	In 2011, 3.47 miles of transmission lines went into service. As these were interconnect transmission lines, no customers were added.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees.	LG&E received FERC authorization in FERC Docket No. ES11-49-000 for up to $500 million in short-term debt through November 30, 2013. LG&E's money pool balance was zero and $12 million at December 31, 2011, and December 31, 2010, respectively. On November 1, 2010, LG&E entered into a new $400 million revolving credit facility maturing December 31, 2014. In October 2011, LG&E amended its syndicated credit facility. The amendment includes extending the expiration date from December 2014 to October 2016. Under this facility, LG&E 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. 2010-00205 on September 30, 2010. The balance outstanding under this line of credit was zero as of December 31, 2011, and $163 million as of December 31, 2010.
7. Changes in articles of incoporation or amendments to charter: Explain the nature and purpose of such changes or amendments.	None.
8. State the estimated annual effect and nature of any important wage scale changes during the year.	During the first quarter of 2011, non-union employees received routine wage increases in accordance with annual salary reviews. In November 2011, LG&E and workers represented by IBEW Local 2100 entered into a 3 year collective bargaining agreement, which included wage increases consistent with market conditions.

Important Changes During the Year (Ref Page: 108)

	Explain
9. State briefly the status of any materially important legal proceedings pending at the end of the year and the results.	See Notes 4, 8 and 18 of Notes to Financial Statements in hard copy form.
10. Describe briefly any materially important transactions not disclosed elsewhere in this report in which an officer, director, or associated company was a party or had a material interest.	None.
11. Estimated increase or decrease in annual revenues caused by important rate changes.	Not applicable.

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
1. UTILITY PLANT		
2. Utility Plant (101-106,114)	$4,361,375,745.00	$4,679,879,565.00
3, Construction Work in Progress (107)	$385,323,919.00	$215,276,377.00
4. TOTAL UTILITY PLANT	$4,746,699,664.00	$4,895,155,942.00
5. (Less) Accum. Prov. for Depr. Amort. Depl. (108,111,115)	$2,043,099,789.00	$2,117,873,453.00
6. Net Utility Plant (Line 4 less Line 5)	$2,703,599,875.00	$2,777,282,489.00
7. Nuclear Fuel (120.1-120.4,120.6)	$0.00	$0.00
8. (Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)	$0.00	$0.00
9. Nuclear Fuel (Line 7 less Line 8)	$0.00	$0.00
10. Net Utility Plant (Enter Total of Line 6 and Line 9)	$2,703,599,875.00	$2,777,282,489.00
11. Utility Plant Adjustments (116)	$0.00	$0.00
12. Gas Stored-Base Gas (117.1)	$2,139,990.00	$2,139,990.00
13. System Balancing Gas (117.2)	$0.00	$0.00
14. Gas Stored Underground - Non Current (117.3)	$0.00	$0.00
15. Gas Owned to System Gas (117.4)	$0.00	$0.00
16. OTHER PROPERTY AND INVESTMENTS		
17. Nonutility Property (121)	$75,240.00	$75,240.00
18. (Less) Accum. Prov. for Depr and Amort. (122)	$63,360.00	$63,360.00
19. Investment in Associated Companies (123)	$0.00	$0.00
20. Investments in Subsidiary Companies (123.1)	$594,286.00	$594,286.00
21.		
22. Noncurrent Portion of Allowances	$0.00	$0.00
23. Other Investments (124)	$0.00	$0.00
24. Special Funds (125-128)	$18,763,174.00	$28,846,730.00
25. TOTAL Other Property and Investments	$19,369,340.00	$29,452,896.00
26. CURRENT AND ACCRUED ASSETS		
27. Cash (131)	$2,025,606.00	$24,920,485.00

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
28. Special Deposits (132-134)	$3,511,015.00	$12,277.00
29. Working Fund (135)	$20,090.00	$20,090.00
30. Temporary Cash Investments (136)	$100,406.00	$33,064.00
31. Notes Receivable (141)	$0.00	$0.00
32. Customer Accounts Receivable (142)	$70,841,405.00	$61,816,182.00
33. Other Accounts Receivable (143)	$15,999,128.00	$12,953,835.00
34. (Less) Accum. Prov. for Uncollectible Acct. Credit (144)	$2,258,397.00	$1,835,907.00
35. Notes Receivable from Associated Companies (145)	$0.00	$0.00
6. Accounts Receivable from Assoc. Companies (146)	$29,799,791.00	$10,916,898.00
37. Fuel Stock (151)	$68,043,290.00	$52,502,546.00
38. Fuel Stock Expenses Undistributed (152)	$0.00	$0.00
39. Residuals (Elec) and Extracted Products (153)	$0.00	$0.00
40. Plant Materials and Operating Supplies (154)	$29,326,916.00	$30,625,942.00
41. Merchandise (155)	$0.00	$0.00
42. Other Materials and Supplies (156)	$0.00	$0.00
43. Nuclear Materials Held for Sale (157)	$0.00	$0.00
44. Allowances (158.1 and 158.2)	$2,729.00	$2,512.00
45. (Less) Noncurrent Portion of Allowances	$0.00	$0.00
46. Stores Expense Undistributed (163)	$4,943,153.00	$5,596,506.00
47. Gas Stored Underground - Current (164.1)	$59,956,181.00	$53,287,604.00
48. Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	$0.00	$0.00
49. Prepayments (165)	$6,832,694.00	$5,472,353.00
50. Advances for Gas (166-167)	$0.00	$0.00
51. Interest and Dividends Receivable (171)	$26,834.00	$25,626.00
52. Rents Receivable (172)	$4,695.00	$3,241.00
53. Accrued Utility Revenues (173)	$78,996,467.00	$64,436,527.00

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
54. Miscellaneous Current and Accrued Assets (174)	$0.00	$0.00
54.a Derivative Instrument Assets (175)	$137,908.00	$0.00
54.b Derivative Instrument Assets - Hedges (176)	$0.00	$0.00
55. TOTAL Current and Accrued Assets (Lines 27 - 54.b)	$368,309,911.00	$320,789,781.00
56. DEFERRED DEBITS		
57. Unamortized Debt Expenses (181)	$9,448,909.00	$9,845,015.00
58. Extraordinary Property Losses (181.1)	$0.00	$0.00
59. Unrecovered Plant and Regulatory Study Costs (182.2)	$0.00	$0.00
60. Other Regulatory Assets (182.3)	$357,713,680.00	$406,124,035.00
61. Prelim. Survey and Investigation Charges (Electric) (183)	$852,033.00	$1,007,070.00
62. Prelim. Sur. and Invest. Charges (Gas) (183.1,183.2)	$0.00	$0.00
63. Clearing Accounts (184)	$0.00	$0.00
64. Temporary Facilities (185)	$0.00	$0.00
65. Miscellaneous Deferred Debits (186)	$600,334,947.00	$550,300,832.00
66. Def. Losses from Disposition of Utility Plt. (187)	$0.00	$0.00
67. Research, Devel. and Demonstration Expend. (188)	$0.00	$0.00
68. Unamortized Loss on Reacquired Debt (189)	$21,934,650.00	$20,963,863.00
69. Accumulated Deferred Income Taxes (190)	$127,207,382.00	$90,900,667.00
70. Unrecovered Purchased Gas Costs (191)	$0.00	
71. TOTAL Deferred Debits (Lines 57-70)	$1,117,491,601.00	$1,079,141,482.00
72. Total Assets and other Debits (Total Lines 10-15,22,55,71)	$4,210,910,717.00	$4,208,806,638.00

Line 2, Column 2:

The majority of the note below provides a summary of all the purchase accounting included in the financial statements for Louisville Gas and Electric Company ("LG&E"). 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.

See additional footnotes in hard copy Annual Gas Report.

Note:

Line 2, Column 2 (cont.):

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 LG&E of $1,702 million. The allocation of the LG&E 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	$	546
Investments		1
Property, plant and equipment		2,935
Other intangible assets		183
Regulatory and other non-current assets		416
Current liabilities		(420)
Affiliated debt		(485)
Debt		(580)
Other non-current liabilities		(1,283)
Net identifiable assets acquired		1,313
Goodwill		389
Total purchase price	$	1,702

Goodwill represents value paid for the rate regulated business of LG&E, 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. LG&E'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 LG&E's assets and liabilities that contributed to goodwill were as follows:

The pollution control bonds, excluding the reacquired bonds, had a fair market value adjustment of $7 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 $87 million based upon an announced transaction by another owner. LG&E's stock was valued at less than $1 million and the power purchase agreement has been valued at $87 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.
- LG&E recorded an emission allowance intangible asset and regulatory liability as the result of adjusting the fair value of the emission allowances at LG&E. The emission allowance fair value of $8 million represents allocated and purchased SO2 and NOx emission allowances that are unused as of the valuation date or allocated for use in future years. LG&E had previously recorded emission allowances as other materials and supplies. This emission allowance fair value adjustment is amortized as the emission allowances are consumed, which is expected to occur through 2040.
- LG&E recorded a coal contract intangible asset of $124 million and a non-current liability of $11 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 LG&E, 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, LG&E 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. LG&E's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

LG&E also considered whether a separate fair value should be assigned to LG&E's rights to operate within its various electric and natural gas 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.

Line 2, Column 3:

This Form 1 is filed reflecting purchase accounting consistent with final accounting entries approved on October 14, 2011, in Docket No. AC11-83-000.

Line 32, Column 2:

The balance in Customer Accounts Receivable (142) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value of Customer Accounts Receivable, LG&E netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of acquisition date. The fair value adjustment is amortized over the period accounts receivable are written off. The following reflects the purchase accounting adjustment:

Customer Accounts Receivable (142) Without Purchase Accounting	$	71,762,183
Purchase Accounting Adjustment		(1,841,558)
Amortization of Purchase Accounting Adjustment		920,780
Total for Customer Accounts Receivable (142)	$	70,841,405

Line 32, Column 3:

The balance in Customer Accounts Receivable (142) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value of Customer Accounts Receivable, LG&E netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of acquisition date. The fair value adjustment is amortized over the period accounts receivable are written off. The following reflects the purchase accounting adjustment:

Customer Accounts Receivable (142) Without Purchase Accounting	$	61,816,182
Purchase Accounting Adjustment		(1,841,558)
2011 Amortization of Purchase Accounting Adjustment		920,778
2010 Amortization of Purchase Accounting Adjustment		920,780
Total for Customer Accounts Receivable (142)	$	61,816,182

Line 33, Column 2:

The balance in Other Accounts Receivable (143) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value of Other Accounts Receivable, LG&E netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of acquisition date. The fair value adjustment is amortized over the period the accounts receivable are written off. The following reflects the purchase accounting adjustment:

Other Accounts Receivable (143) Without Purchase Accounting	$	17,424,788
Purchase Accounting Adjustment		(1,768,320)
Amortization of Purchase Accounting Adjustment		342,660
Total for Other Accounts Receivable (143)	$	15,999,128

Line 33, Column 3:

The balance in Other Accounts Receivable (143) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value of Other Accounts Receivable, LG&E netted previously recorded Accumulated Provision for Uncollectible Accounts against the book value of assets as of acquisition date. The fair value adjustment is amortized over the period the accounts receivable are written off. The following reflects the purchase accounting adjustment:

Other Accounts Receivable (143) Without Purchase Accounting	$	12,953,835
Purchase Accounting Adjustment		(1,768,320)
2011 Amortization of Purchase Accounting Adjustment		1,425,660
2010 Amortization of Purchase Accounting Adjustment		342,660
Total for Other Accounts Receivable (143)	$	12,953,835

Line 34, Column 2:

The balance in Accumulated Provision For Uncollectible Accounts (144) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value of Customer Accounts Receivable and Other Accounts Receivable, LG&E 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	$	4,604,835
Purchase Accounting Adjustment		(3,609,878)
Amortization of Purchase Accounting Adjustment		1,263,440
Total for Accum. Prov. For Uncollectible Acct. (144)	$	2,258,397

Line 34, Column 3:

The balance in Accumulated Provision For Uncollectible Accounts (144) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value of Customer Accounts Receivable and Other Accounts Receivable, LG&E 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	$	1,835,907
Purchase Accounting Adjustment		(3,609,878)
2011 Amortization of Purchase Accounting Adjustment		2,346,438
2010 Amortization of Purchase Accounting Adjustment		1,263,440
Total for Accum. Prov. For Uncollectible Acct. (144)	$	1,835,907

Line 36, Column 3:
The decrease is due to intercompany tax settlements that were outstanding in December 31, 2010.

Line 54, Column 3:
All derivative transactions were liquidated and settled in the fourth quarter of 2011 due to MF Global's bankruptcy.

Line 57, Column 2:
The balance in Unamortized Debt Expenses (181) was adjusted due to the purchase of LG&E by PPL in November 2010, as these costs are considered to have no fair value in purchase accounting under US GAAP. However, since LG&E receives recovery of these costs in rates through the embedded cost of capital, the balance of $3,698,836 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 Expenses (181)	$	13,116,651
Purchase Accounting Adjustment		(3,698,836)
Amortization of Purchase Accounting Adjustment		31,094
Total for Unamortized Debt Expenses (181)	$	9,448,909

First mortgage bonds were issued November 16, 2010, resulting in debt issuance expense of $5,424,700 to be amortized over the life of the related issues, of which $62,888 was amortized through December 31, 2010. A revolving credit facility was set up on November 1, 2010, resulting in setup fees of $4,256,182 to be amortized over the term of the credit facility, of which $169,085 was amortized through December 31, 2010.

Line 57, Column 3:

The balance in Unamortized Debt Expenses (181) was adjusted due to the purchase of LG&E by PPL in November 2010, as these costs are considered to have no fair value in purchase accounting under US GAAP. However, since LG&E receives recovery of these costs in rates through the embedded cost of capital, the balance of $3,698,836 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 Expenses (181)	$	13,326,195
Purchase Accounting Adjustment		(3,698,836)
2011 Amortization of Purchase Accounting Adjustment		186,562
2010 Amortization of Purchase Accounting Adjustment		31,094
Total for Unamortized Debt Expenses (181)	$	9,845,015

Line 60, Column 2:

The balance in Other Regulatory Assets (182.3) was adjusted to reflect regulatory offsets due to the purchase of LG&E 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, fair value of interest rate swaps based on the mark-to-market value for the swaps, 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.

Other Regulatory Assets (182.3) Without Purchase Accounting	$	344,036,364
Purchase Accounting Adjustment - Unamortized Debt Expenses (from account 181)		3,698,836
Amortization of Purchase Accounting Adjustment - Unamortized Debt Expenses		(31,094)
Purchase Accounting Adjustment - terminated interest rate swap		2,050,000
Amortization of Purchase Accounting Adjustment - terminated interest rate swap		(2,050,000)
Purchase Accounting Adjustment - coal supply contracts		11,265,929
Amortization of Purchase Accounting Adjustment - coal supply contracts		(2,051,068)
Purchase Accounting Adjustment - rent commitments		794,713
Total for Other Regulatory Assets (182.3) Purchase Accounting	$	357,713,680

Line 60, Column 3:

The balance in Other Regulatory Assets (182.3) was adjusted to reflect regulatory offsets due to the purchase of LG&E 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.

Other Regulatory Assets (182.3) Without Purchase Accounting	$	397,110,901
Purchase Accounting Adjustment - Unamortized Debt Expenses (from account 181)		3,698,836
2011 Amortization of Purchase Accounting Adjustment - Unamortized Debt Expenses		(186,562)
2010 Amortization of Purchase Accounting Adjustment - Unamortized Debt Expenses		(31,094)
Purchase Accounting Adjustment - coal supply contracts		11,265,929
2011 Amortization of Purchase Accounting Adjustment - coal supply contracts		(4,282,428)
2010 Amortization of Purchase Accounting Adjustment - coal		

supply contracts		(2,051,068)
Purchase Accounting Adjustment - rent commitments		794,713
2011 Amortization of Purchase Accounting Adjustment - rent commitments		(195,192)
Total for Other Regulatory Assets (182.3) Purchase Accounting	$	406,124,035

Line 65, Column 2:

The balance in Miscellaneous Deferred Debits (186) was adjusted due to the purchase of LG&E by PPL in November 1, 2010. The account was adjusted for coal supply contracts, a power purchase contract, emission allowances and goodwill attributed to LG&E. 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 LG&E's megawatt capacity. The value assigned to the purchase power contract was the difference between LG&E's original investment and the $87 million for LG&E. 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 allowances, ending in December 2040. 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. The following reflects the purchase accounting adjustments:

Miscellaneous Deferred Debits (186) Without Purchase Accounting	$	275,027
Purchase Accounting Adjustment - power purchase contract		86,856,705
Amortization of Purchase Accounting Adjustment - power purchase contract		(1,047,496)
Purchase Accounting Adjustment - emission allowances		8,359,713
Amortization of Purchase Accounting Adjustment - emission allowances		(926,313)
Purchase Accounting Adjustment - coal supply contracts		123,813,249
Amortization of Purchase Accounting Adjustment - coal supply contracts		(6,153,288)
Goodwill		389,157,352
Rounding		(2)
Total for Miscellaneous Deferred Debits (186)	$	600,334,947

Line 65, Column 3:

The balance in Miscellaneous Deferred Debits (186) was adjusted due to the purchase of LG&E by PPL in November 1, 2010. The account was adjusted for coal supply contracts, a power purchase contract, emission allowances and goodwill attributed to LG&E. 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 LG&E's megawatt capacity. The value assigned to the purchase power contract was the difference between LG&E's original investment and the $87 million for LG&E. 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 allowances, ending in December 2040. 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. The following reflects the purchase accounting adjustments:

Miscellaneous Deferred Debits (186) Without Purchase Accounting	$	473,638
Purchase Accounting Adjustment - power purchase contract		86,856,705
2011 Amortization of Purchase Accounting Adjustment - power purchase contract		(5,472,941)
2010 Amortization of Purchase Accounting Adjustment - power		

purchase contract		(1,047,496)
Purchase Accounting Adjustment - emission allowances		8,359,713
2011 Amortization of Purchase Accounting Adjustment - emission allowances		(5,419,213)
2010 Amortization of Purchase Accounting Adjustment - emission allowances		(926,313)
Purchase Accounting Adjustment - coal supply contracts		123,813,249
2011 Amortization of Purchase Accounting Adjustment - coal supply contracts		(39,340,574)
2010 Amortization of Purchase Accounting Adjustment - coal supply contracts		(6,153,288)
Goodwill		389,157,352
Total for Miscellaneous Deferred Debits (186)	$	550,300,832

Line 69, Column 2:

The balance in Accumulated Deferred Income Taxes (190) was adjusted due to the purchase of LG&E 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 rent commitment, 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. The following reflects the purchase accounting adjustment:

Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$	38,744,526
Purchase Accounting Adjustment - pollution control bonds		2,558,343
Amortization of Purchase Accounting Adjustment - pollution control bonds		(19,464)
Purchase Accounting Adjustment - power purchase contract		33,787,258
Amortization of Purchase Accounting Adjustment - power purchase contract		(407,476)
Purchase Accounting Adjustment - interest rate swap		797,450
Amortization of Purchase Accounting Adjustment - interest rate swap		(797,450)
Purchase Accounting Adjustment - emission allowances		3,251,929
Amortization of Purchase Accounting Adjustment - emission allowances		(360,336)
Purchase Accounting Adjustment - regulatory liability coal supply contracts		48,163,354
Amortization of Purchase Accounting Adjustment - regulatory liability for coal supply contracts		(2,393,629)
Purchase Accounting Adjustment - coal supply contracts		4,382,446
Amortization of Purchase Accounting Adjustment - coal supply contracts		(797,865)
Purchase Accounting Adjustment - rent commitment		309,143
Amortization of Purchase Accounting Adjustment - rent commitment		(10,847)
Total for Accumulated Deferred Income Taxes (190)	$	127,207,382

Line 69, Column 3:

The balance in Accumulated Deferred Income Taxes (190) was adjusted due to the purchase of LG&E 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 rent commitment, 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. The following reflects the purchase accounting adjustment:

Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$	23,826,072
Purchase Accounting Adjustment - pollution control bonds		2,558,343

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Balance Sheet - Assets and Other Debits (Ref Page: 110) - NOTES

2011 Amortization of Purchase Accounting Adjustment - pollution control bonds	(116,782)
2010 Amortization of Purchase Accounting Adjustment - pollution control bonds	(19,464)
Purchase Accounting Adjustment - power purchase contract	33,787,258
2011 Amortization of Purchase Accounting Adjustment - power purchase contract	(2,128,974)
2010 Amortization of Purchase Accounting Adjustment - power purchase contract	(407,476)
Purchase Accounting Adjustment - interest rate swap	797,450
2010 Amortization of Purchase Accounting Adjustment - interest rate swap	(797,450)
Purchase Accounting Adjustment - emission allowances	3,251,929
2011 Amortization of Purchase Accounting Adjustment - emission allowances	(2,108,074)
2010 Amortization of Purchase Accounting Adjustment - emission allowances	(360,336)
Purchase Accounting Adjustment - regulatory liability coal supply contracts	48,163,354
2011 Amortization of Purchase Accounting Adjustment - regulatory liability for coal supply contracts	(15,303,484)
2010 Amortization of Purchase Accounting Adjustment - regulatory liability for coal supply contracts	(2,393,629)
Purchase Accounting Adjustment - coal supply contracts	4,382,446
2011 Amortization of Purchase Accounting Adjustment - coal supply contracts	(1,665,864)
2010 Amortization of Purchase Accounting Adjustment - coal supply contracts	(797,865)
Purchase Accounting Adjustment - rent commitment	309,143
2011 Amortization of Purchase Accounting Adjustment - rent commitment	(65,083)
2010 Amortization of Purchase Accounting Adjustment - rent commitment	(10,847)
Total for Accumulated Deferred Income Taxes (190)	$ 90,900,667

Balance Sheet - Liabilities and Other Credits (Ref Page: 112)

	Balance Beginning of Year	Balance End of Year
1. PROPRIETARY CAPITAL		
2. Common Stock Issued (201)	$425,170,424.00	$425,170,424.00
3. Preferred Stock Issued (204)	$0.00	$0.00
4. Capital Stock Subscribed (202,205)	$0.00	$0.00
5. Stock Liability for Conversion (203,206)	$0.00	$0.00
6. Premium on Capital Stock (207)	$0.00	$0.00
7. Other Paid-in Capital Stock (208-211)	$1,277,667,368.00	$1,277,667,368.00
8. Installments Received on Capital stock (212)	$0.00	$0.00
9. (Less) Discount on Capital Stock (213)	$0.00	$0.00
10. (Less) Capital Stock Expense (214)	$835,889.00	$835,889.00
11. Retained Earnings (215,215.1,216)	$19,093,970.00	$60,196,667.00
12. Unappropriated Undistributed Subsidaiary Earnings (216.1)	$0.00	$0.00
13. (Less) Reacquired Capital Stock (217)	$0.00	$0.00
14. Accumulated Other Comprehensive Income (219)	$0.00	$0.00
15. TOTAL Proprietary Capital	$1,721,095,873.00	$1,762,198,570.00
16. LONG TERM DEBT		
17. Bonds (221)	$1,109,304,000.00	$1,109,304,000.00
18. (Less) Reacquired Bonds (222)	($163,200,000.00)	$0.00
19. Advances from Associated Companies (223)	$0.00	$0.00
20. Other Long-Term Debt (224)	$6,526,682.00	$6,226,470.00
21. Unamortized Premium on Long-Term Debt (225)	$0.00	$0.00
22. (Less) Unamortized Discount on LongTerm Debt (226)	$3,948,318.00	$3,668,458.00
23. (Less) Current Portion of Long Term Debt	$0.00	$0.00
24. TOTAL Long Term Debt	$948,682,364.00	$1,111,862,012.00
25. OTHER NONCURRENT LIABILITIES		
26. Obligations Under Capital Leases-NonCurrent (227)	$0.00	$0.00
27. Accumulated Provision for Property Insurance (228.1)	$0.00	$0.00

Balance Sheet - Liabilities and Other Credits (Ref Page: 112)

	Balance Beginning of Year	Balance End of Year
28. Accumulated Provision for Injuries and Damages (228.2)	$4,121,200.00	$5,691,293.00
29. Accumulated Provision for Pensions and Benefits (228.3)	$213,591,951.00	$184,133,495.00
30. Accumulated Miscellaneous Operating Provisions (228.4)	$0.00	$0.00
31. Accumulated Provision for Rate Refunds (229)	$0.00	$0.00
32. Asset Retirement Obligations (230)	$52,650,789.00	$58,606,350.00
33. TOTAL OTHER Noncurrent Liabilities	$270,363,940.00	$248,431,138.00
34. CURRENT AND ACCRUED LIABILITIES		
35. Current Portion of Long-Term Debt	$0.00	$0.00
36. Notes Payable (231)	$163,000,000.00	$0.00
37. Accounts Payable (232)	$104,974,357.00	$97,848,808.00
38. Notes Payable to Associated Companies (233)	$11,876,000.00	$0.00
39. Account Payable to Associated Companies (234)	$19,944,791.00	$25,528,426.00
40. Customer Deposits (235)	$23,237,609.00	$22,361,042.00
41. Taxes Accrued (236)	$9,598,153.00	$13,284,850.00
42. Interest Accrued (237)	$5,235,853.00	$5,825,755.00
43. Dividends Declared (238)	$0.00	$0.00
44. Matured Long-Term Debt (239)	$0.00	$0.00
45. Matured Interests (240)	$0.00	$0.00
46. Tax Collections Payable (241)	$1,275,524.00	$1,090,154.00
47. Miscellaneous current and Accrued Liabilities (242)	$19,381,570.00	$16,535,301.00
48. Obligatons Under Capital Leases - Current (243)	$0.00	$0.00
49. Derivative Instrument Liabilities (244)	$15,850,565.00	$32,541,878.00
50. Derivative Instrument Liabilties - Hedges (245)	$19,972,749.00	$27,024,586.00
51. TOTAL Current and Accrued Liabilities	$394,347,171.00	$242,040,800.00
52. DEFERRED CREDITS		
53. Customer Advances for Construction (252)	$8,580,930.00	$7,307,169.00
54. Accumulated Deferred Investment Tax Credits (255)	$45,524,576.00	$42,718,844.00

Balance Sheet - Liabilities and Other Credits (Ref Page: 112)

	Balance Beginning of Year	Balance End of Year
55. Deferred Gains from Disposition of Utility Plant (256)	$0.00	$0.00
56. Other Deferred Credits (253)	$15,658,759.00	$10,652,321.00
57. Other Regulatory Liabilities (254)	$262,328,918.00	$219,287,438.00
58. Unamortized gain on Reacquired Debt (257)	$0.00	$0.00
59. Accumulated Deferred Income Taxes (281-283)	$544,328,186.00	$564,308,346.00
60. TOTAL Deferred Credits	$876,421,369.00	$844,274,118.00
61. TOTAL Liabilities and Other Credits (Total Lines 15,24,33,51 and 60)	$4,210,910,717.00	$4,208,806,638.00

Note:
Line 7, Column 2:

The balance in Other Paid-in Capital (208-211) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value, the balance was adjusted for the fixed rate pollution control bonds net of deferred taxes and goodwill. The balance also includes elimination of Retained Earnings (215, 215.1, 216) at October 31, 2010.

See additional footnotes in hard copy Annual Gas Report.

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Balance Sheet - Liabilities and Other Credits (Ref Page: 112) - NOTES

Line 7, Column 2 (cont.):

Other Paid-in Capital (208-211) Without Purchase Accounting	$	83,581,499
Purchase Accounting Adjustment - fixed rate pollution control bonds		(4,018,374)
Purchase Accounting Adjustment - goodwill		389,157,352
Purchase Accounting Adjustment - prior retained earnings		808,946,891
Total for Other Paid-in Capital (208-211)	$	1,277,667,368

Line 7, Column 3;
The balance in Other Paid-in Capital (208-211) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value, the balance was adjusted for the fixed rate pollution control bonds net of deferred taxes and goodwill. The balance also includes elimination of Retained Earnings (215, 215.1, 216) at October 31, 2010. The following reflects the purchase accounting adjustment:

Other Paid-in Capital (208-211) Without Purchase Accounting	$	83,581,499
Purchase Accounting Adjustment - fixed rate pollution control bonds		(4,018,374)
Purchase Accounting Adjustment - goodwill		389,157,352
Purchase Accounting Adjustment - prior retained earnings		808,946,891
Total for Other Paid-in Capital (208-211)	$	1,277,667,368

Line 11, Column 2:
The balance in Retained Earnings (215, 215.1, 216) was adjusted due to the purchase of LG&E 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. The following reflects the purchase accounting adjustment:

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$	827,993,252
Purchase Accounting Adjustment		(808,946,891)
Amortization of Purchase Accounting Adjustment - rent commitment (net of deferred taxes of $(10,848)		17,037
Amortization of Purchase Accounting Adjustment - pollution control bonds (net of deferred taxes of $19,463)		30,572
Total for Retained Earnings (215, 215.1, 216)	$	19,093,970

Line 11, Column 3:
The balance in Retained Earnings (215, 215.1, 216) was adjusted due to the purchase of LG&E 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. The following reflects the purchase accounting adjustment:

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$	868,929,557
Purchase Accounting Adjustment		(808,946,891)
2011 Amortization of Purchase Accounting Adjustment - rent commitment (net of deferred taxes of $(10,848)		(17,037)
2010 Amortization of Purchase Accounting Adjustment - rent commitment (net of deferred taxes of $10,848)		17,037
2011 Amortization of Purchase Accounting Adjustment - pollution control bonds (net of deferred taxes of $116,783)		183,429
2010 Amortization of Purchase Accounting Adjustment - pollution control bonds (net of deferred taxes of $19,463)		30,572
Total for Retained Earnings (215, 215.1, 216)	$	60,196,667

Line 18, Column 3:
Available for sale bonds were remarketed during first quarter of 2011.

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Balance Sheet - Liabilities and Other Credits (Ref Page: 112) - NOTES

Line 20, Column 2:

The balance in Other Long-Term Debt (224) was adjusted due to the purchase of LG&E 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		6,576,717
Amortization of Purchase Accounting Adjustment		(50,035)
Total for Other Long-Term Debt (224)	$	6,526,682

Line 20, Column 3:

The balance in Other Long-Term Debt (224) was adjusted due to the purchase of LG&E 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		6,576,717
2011 Amortization of Purchase Accounting Adjustment		(300,212)
2010 Amortization of Purchase Accounting Adjustment		(50,035)
Total for Other Long-Term Debt (224)	$	6,226,470

Line 36, Column 3:

Prior balance represents drawdown on Wachovia Credit Facility for $163,000,000 in November 2010 paid off during first quarter of 2011.

Line 38, Column 3:

Balance represents drawdown of money pool in fourth quarter 2010 paid off during the first quarter of 2011.

Line 49, Column 2:

The balance in Derivative Instrument Liabilities (244) was adjusted due to the purchase of LG&E by PPL in November 2010. The amount recorded ($1,570,000) reflects a credit valuation adjustment at the acquisition date. The following reflects the purchase accounting adjustment:

Derivative Instrument Liabilities (244) Without Purchase Accounting	$	15,850,565
Purchase Accounting Adjustment		1,570,000
Amortization of Purchase Accounting Adjustment		(1,570,000)
Total for Derivative Instrument Liabilities (244)	$	15,850,565

Line 49, Column 3:

The balance in Derivative Instrument Liabilities (244) was adjusted due to the purchase of LG&E by PPL in November 2010. The amount recorded ($1,570,000) reflects a credit valuation adjustment at the acquisition date. The following reflects the purchase accounting adjustment:

Derivative Instrument Liabilities (244) Without Purchase Accounting	$	32,541,878
Purchase Accounting Adjustment		1,570,000
2010 Amortization of Purchase Accounting Adjustment		(1,570,000)
Total for Derivative Instrument Liabilities (244)	$	32,541,878

Line 50, Column 2:

The balance in Derivative Instrument Liabilities - Hedging (245) was adjusted due to the purchase of LG&E by PPL in November 2010. The amount recorded ($480,000) reflects a credit valuation adjustment at the acquisition date. The following reflects the purchase accounting adjustment:

Derivative Instrument Liabilities - Hedging (245) Without Purchase Accounting	$	19,972,749
Purchase Accounting Adjustment		480,000
Amortization of Purchase Accounting Adjustment		(480,000)
Total for Derivative Instrument Liabilities - Hedging (245)	$	19,972,749

Line 50, Column 3:

The balance in Derivative Instrument Liabilities - Hedging (245) was adjusted due to the purchase of LG&E by PPL in November 2010. The amount recorded ($480,000) reflects a credit valuation adjustment at the acquisition date. The following reflects the purchase accounting adjustment:

Derivative Instrument Liabilities - Hedging (245) Without Purchase Accounting	$	27,024,586
Purchase Accounting Adjustment		480,000
2010 Amortization of Purchase Accounting Adjustment		(480,000)
Total for Derivative Instrument Liabilities - Hedging (245)	$	27,024,586

Line 56, Column 2:

The balance in Other Deferred Credits (253) was adjusted due to the purchase of LG&E 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. The following reflects the purchase accounting adjustments:

Other Deferred Credits Without Purchase Accounting	$	5,677,070
Purchase Accounting Adjustment - coal supply contracts		11,265,929
Amortization of Purchase Accounting Adjustment - coal supply contracts		(2,051,068)
Purchase Accounting Adjustment - rent commitment		794,713
Amortization of Purchase Accounting Adjustment - rent commitment		(27,885)
Total for Other Deferred Credits (253)	$	15,658,759

Line 56, Column 3:

The balance in Other Deferred Credits (253) was adjusted due to the purchase of LG&E 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. The following reflects the purchase accounting adjustments:

Other Deferred Credits Without Purchase Accounting	$	5,120,368
Purchase Accounting Adjustment - coal supply contracts		11,265,929
2011 Amortization of Purchase Accounting Adjustment - coal supply contracts		(4,282,428)
2010 Amortization of Purchase Accounting Adjustment -		

coal supply contracts		(2,051,068)
Purchase Accounting Adjustment - rent commitment		794,713
2011 Amortization of Purchase Accounting Adjustment - rent commitment		(167,308)
2010 Amortization of Purchase Accounting Adjustment - rent commitment		(27,885)
Total for Other Deferred Credits (253)	$	10,652,321

Line 57, Column 2:

The balance in Other Regulatory Liabilities (254) was adjusted to reflect regulatory offset due to the purchase of LG&E 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 LG&E's megawatt capacity. The value assigned to the purchase power contract was the difference between LG&E's original investment and the $87 million for LG&E.

The balances will be amortized as the underlying purchase accounting adjustments are amortized. The following reflects the purchase accounting adjustments:

Other Regulatory Liabilities (254) Without Purchase Accounting	$	51,426,348
Purchase Accounting Adjustment - coal supply contracts		123,813,249
Amortization of Purchase Accounting Adjustment - coal supply contracts		(6,153,288)
Purchase Accounting Adjustment - emission allowances		8,359,713
Amortization of Purchase Accounting Adjustment - emission allowances		(926,313)
Purchase Accounting Adjustment - power purchase contract		86,856,705
Amortization of Purchase Accounting Adjustment - power purchase contract		(1,047,496)
Total for Other Regulatory Liabilities (254)	$	262,328,918

Line 57, Column 3:

The balance in Other Regulatory Liabilities (254) was adjusted to reflect regulatory offset due to the purchase of LG&E 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 LG&E's megawatt capacity. The value assigned to the purchase power contract was the difference between LG&E's original investment and the $87 million for LG&E.

The balances will be amortized as the underlying purchase accounting adjustments are amortized. The following reflects the purchase accounting adjustments:

Other Regulatory Liabilities (254) Without Purchase Accounting	$	58,617,596
Purchase Accounting Adjustment - coal supply contracts		123,813,249
2011 Amortization of Purchase Accounting Adjustment - coal supply contracts		(39,340,574)
2010 Amortization of Purchase Accounting Adjustment - coal		

supply contracts		(6,153,288)
Purchase Accounting Adjustment - emission allowances		8,359,713
2011 Amortization of Purchase Accounting Adjustment - emission allowances		(5,419,213)
2010 Amortization of Purchase Accounting Adjustment - emission allowances		(926,313)
Purchase Accounting Adjustment - power purchase contract		86,856,705
2011 Amortization of Purchase Accounting Adjustment - power purchase contract		(5,472,941)
2010 Amortization of Purchase Accounting Adjustment - power purchase contract		(1,047,496)
Total for Other Regulatory Liabilities (254)	$	219,287,438

Line 59, Column 2:

The balance in Accumulated Deferred Income Taxes - Other (283) was adjusted due to the purchase of LG&E by PPL in November 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. The following reflects the purchase accounting adjustments:

Accum. Deferred Income Taxes-Other (281-283) Without Purchase Accounting	$	458,393,362
Purchase Accounting Adjustment - power purchase contract		33,787,258
Amortization of Purchase Accounting Adjustment - power purchase contract		(407,476)
Purchase Accounting Adjustment - emission allowances		3,251,929
Amortization of Purchase Accounting Adjustment - emission allowances		(360,336)
Purchase Accounting Adjustment - coal supply contracts		48,163,354
Amortization of Purchase Accounting Adjustment - coal supply contracts		(2,393,629)
Purchase Accounting Adjustment - regulatory asset for coal supply contracts		4,382,446
Amortization of Purchase Accounting Adjustment - regulatory asset for coal supply contracts		(797,865)
Purchase Accounting Adjustment - rent commitment		309,143
Purchase Accounting Adjustment - interest rate swap		797,450
Amortization of Purchase Accounting Adjustment - interest rate swap		(797,450)
Total for Accum. Deferred Income Taxes-other (281-283)	$	544,328,186

Line 59, Column 3:

The balance in Accumulated Deferred Income Taxes - Other (283) was adjusted due to the purchase of LG&E by PPL in November 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. The following reflects the purchase accounting adjustments:

Accum. Deferred Income Taxes-Other (281-283) Without Purchase Accounting	$	499,655,848
Purchase Accounting Adjustment - power purchase contract		33,787,258
2011 Amortization of Purchase Accounting Adjustment - power purchase contract		(2,128,974)

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2010 Amortization of Purchase Accounting Adjustment - power purchase contract	(407,476)
Purchase Accounting Adjustment - emission allowances	3,251,929
2011 Amortization of Purchase Accounting Adjustment - emission allowances	(2,108,074)
2010 Amortization of Purchase Accounting Adjustment - emission allowances	(360,336)
Purchase Accounting Adjustment - coal supply contracts	48,163,354
2011 Amortization of Purchase Accounting Adjustment - coal supply contracts	(15,303,484)
2010 Amortization of Purchase Accounting Adjustment - coal supply contracts	(2,393,629)
Purchase Accounting Adjustment - regulatory asset for coal supply contracts	4,382,446
2011 Amortization of Purchase Accounting Adjustment - regulatory asset for coal supply contracts	(1,665,864)
2010 Amortization of Purchase Accounting Adjustment - regulatory asset for coal supply contracts	(797,865)
Purchase Accounting Adjustment - rent commitment	309,143
2011 Amortization of Purchase Accounting Adjustment - rent commitment	(75,930)
Purchase Accounting Adjustment - interest rate swap	797,450
2010 Amortization of Purchase Accounting Adjustment - interest rate swap	(797,450)
Total for Accum. Deferred Income Taxes-other (281-283)	$ 564,308,346

Statement of Income for the Year (Ref Page: 114)

	Total (c)	Total - Prev Yr (d)	Electric (e)	Gas (g)	Other (i)
1..UTILITY OPERATING INCOME					
2. Gas Operating Revenues (400)	$1,364,324,725.00	$1,318,558,923.00	$1,059,750,303.00	$304,574,422.00	$0.00
3. Operating Expenses					
4. Operation Expenses (401)	$833,403,806.00	$818,724,773.00	$627,435,850.00	$205,967,956.00	$0.00
5. Maintenance Expenses (402)	$116,359,069.00	$111,701,105.00	$96,235,088.00	$20,123,981.00	$0.00
6. Depreciation Expense (403)	$138,912,614.00	$130,224,377.00	$118,859,674.00	$20,052,940.00	$0.00
7. Depreciation Expense for Asset Retirement Costs (403.1)	$3,085,601.00	$985,626.00	$2,062,146.00	$1,023,455.00	$0.00
8. Amort and Depl of Utility Plant (404-405)	$8,133,464.00	$7,726,989.00	$5,774,759.00	$2,358,705.00	$0.00
9. Amort of Utility Plant Acq. Adj (406)	$0.00	$0.00	$0.00	$0.00	$0.00
10. Amort of Property Losses, Unrecovered Plant and Regulatory Study Costs (407.1)	$0.00	$0.00	$0.00	$0.00	$0.00
11. Amort. of Conversion Expenses (407.2)	$0.00	$0.00	$0.00	$0.00	$0.00
12. Regulatory Debits (407.3)	$0.00	$0.00	$0.00	$0.00	$0.00
13. (Less) Regulatory Credits (407.4)	$5,730,086.00	$4,269,732.00	$3,694,954.00	$2,035,132.00	$0.00
14. Taxes Other than Income Taxes (408.1)	$28,121,584.00	$22,571,624.00	$21,610,185.00	$6,511,399.00	$0.00
15. Income Taxes - Federal (409.1)	$11,962,850.00	$28,874,607.00	$27,439,817.00	($15,476,967.00)	$0.00
16. Income Taxes - Other (409.1)	$8,265,533.00	$6,047,168.00	$9,971,422.00	($1,705,889.00)	$0.00

Statement of Income for the Year (Ref Page: 114)

	Total (c)	Total - Prev Yr (d)	Electric (e)	Gas (g)	Other (i)
17. Provision for Deferred Income Taxes (410.1)	$253,017,989.00	$259,414,153.00	$183,640,810.00	$69,377,179.00	$0.00
18. (Less) Provision for Deferred Income Taxes (411.1)	$198,676,654.00	$229,346,812.00	$171,441,026.00	$27,235,628.00	$0.00
19. Investment Tax Credit Adj. - Net (411.4)	($2,805,732.00)	($2,501,774.00)	($2,670,412.00)	($135,320.00)	$0.00
20. (Less) Gains from Disp. of Utility Plant (411.6)	$0.00	$0.00	$0.00	$0.00	$0.00
21. Losses from Disp. of Utility Plant (411.7)	$0.00	$0.00	$0.00	$0.00	$0.00
22. (Less) Gains from Disposition of Allowances (411.8)	$2,578.00	$34,460.00	$2,578.00	$0.00	$0.00
23. Losses from Disposition of Allowances (411.9)	$0.00	$0.00	$0.00	$0.00	$0.00
24. Accretion Expense (411.10)	$2,644,484.00	$3,284,105.00	$1,632,808.00	$1,011,676.00	$0.00
25. Total Utility Operating Expenses (Enter Total of Lines 4 - 22)	$1,196,691,944.00	$1,153,401,749.00	$916,853,589.00	$279,838,355.00	$0.00
26. Net Utility Operating Income (Line 2 less line 23 - Carry forward to pg 117 line 25)	$167,632,781.00	$165,157,174.00	$142,896,714.00	$24,736,067.00	$0.00

Note:
Line 4, Column C:
The balance in Operation Expenses (401) was adjusted due to the purchase of LG&E 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.

See additional footnotes in hard copy Annual Gas Report.

Statement of Income (continued) (Ref Page: 116)

	Current Year	Previous Year
27. Net Utility Operating Income (Carried from pg 114)	$167,632,781.00	$165,157,174.00
28. Other Income and Deductions		
29. Other Income		
30. Nonutility Operating Income		
31. Revenues From Merchandising, Jobbing and Contract Work (415)	$150.00	$2,175.00
32. (Less) Costs and Exp. of Merchandising,Job. and Contract Work (416)	$21,101.00	$22,971.00
33. Revenues From Nonutility Operations (417)	$1,217,684.00	$1,386,069.00
34. (Less) Expenses of Nonutility Operations (417.1)	$0.00	$0.00
35. Nonoperating Rental Income (418)	$0.00	$0.00
36. Equity in Earnings of Subsidiary Companies (418.1)	$0.00	$0.00
37. Interest and Dividend Income (419)	$138,410.00	$176,917.00
38. Allowance for Other Funds Used During Construction (419.1)	$0.00	$0.00
39. Miscellaneous Nonoperating Income (421)	$1,049,402.00	($868,570.00)
40. Gain on Disposition of Property (421.1)	$69,454.00	$33,760.00
41. TOTAL Other Income	$2,453,999.00	$707,380.00
42. Other Income Deductions		
43. Loss on Disposition of Property (421.2)	$0.00	$0.00
44. Miscellaneous Amortization (425)		$0.00
45. Miscellaneous Income Deductions (426.1 - 426.5)	$2,125,557.00	($16,228,823.00)
46.TOTAL Other Income Deductions	$2,125,557.00	($16,228,823.00)
47. Taxes Applic. to Other Income and Deductions		
48. Taxes Other Than Income Taxes (408.2)	$3,168.00	$2,541.00
49. Income Taxes - Federal (409.2)	($489,148.00)	($375,489.00)
50. Income Taxes - Other (409.2)	($90,284.00)	($70,710.00)
51. Provision for Deferred Inc. Taxes (410.2)	$2,320,167.00	$9,694,373.00

Statement of Income (continued) (Ref Page: 116)

	Current Year	Previous Year
52. (Less) Provision for Deferred Income Taxes CR (411.2)	$2,494,859.00	$3,031,984.00
53. Investment Tax Credit Adj. Net (411.5)	$0.00	$0.00
54. (Less) Investment Tax Credits (420)	$0.00	$0.00
55. TOTAL Taxes on Other Income and Deduct.	($750,956.00)	$6,218,731.00
56. Net Other Income and Deductions (Lines 39,44,53)	$1,079,398.00	$10,717,472.00
57. Interest Charges		
58. Interest on Long Term Debt (427)	$38,509,524.00	$20,524,437.00
59. Amort of Debt Disc. and Expense (428)	$2,098,127.00	$453,375.00
60. Amortization of Loss on Reacquired Debt (428.1)	$1,213,346.00	$1,211,251.00
61. (Less) Amort. of Premium on Debt - CR (429)	$0.00	$0.00
62. (Less) Amortization of Gain on Reacquired Debt - CR (429.1)	$0.00	$0.00
63. Interest on Debt to Assoc. Companies (430)	$9,663.00	$23,582,997.00
64. Other Interest Expense (431)	$2,528,822.00	$2,340,591.00
65. (Less) Allowance for Borrowed Funds Used During Construction CR (432)	$0.00	$0.00
66. Net Interest Charges	$44,359,482.00	$48,112,651.00
67. Income Before Extraordinay Items (Lines 25,54 and 64)	$124,352,697.00	$127,761,995.00
68. Extraordinary Items		
69. Extraordinary Income (434)	$0.00	$0.00
70. (Less) Extraordinary Deductions (435)	$0.00	$0.00
71. Net Extraordinary Items (Lines 67 less 68)	$0.00	$0.00
72. Income Taxes - Federal and Other (409.3)	$0.00	$0.00
73. Extraordinary Items After Taxes (Lines 69 less 70)	$0.00	$0.00
74. Net Income (Lines 67 and 73)	$124,352,697.00	$127,761,995.00

Line 4, Column C (cont.):

Operation Expenses (401) Without Purchase Accounting	$	833,375,921
Amortization of Purchase Accounting Adjustment		27,885
Total for Operation Expenses (401)	$	833,403,806

Line 4, Column D:

The balance in Operation Expenses (401) was adjusted due to the purchase of LG&E 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	$	818,752,658
Amortization of Purchase Accounting Adjustment		(27,885)
Total for Operation Expenses (401)	$	818,724,773

Line 4, Column E:

The balance in Operation Expenses (401) was adjusted due to the purchase of LG&E 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	$	627,413,263
Amortization of Purchase Accounting Adjustment		22,587
Total for Operation Expenses (401)	$	627,435,850

Line 4, Column G:

The balance in Operation Expenses (401) was adjusted due to the purchase of LG&E 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	$	205,962,658
Amortization of Purchase Accounting Adjustment		5,298
Total for Operation Expenses (401)	$	205,967,956

Line 17, Column C:

The balance in Provision for Deferred Income Taxes (410.1) was adjusted due to the purchase of LG&E by PPL in November 2010. The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$	228,816,570
Purchase Accounting Adjustment - coal contract		18,801,514
Purchase Accounting Adjustment - emission allowance		2,335,680
Purchase Accounting Adjustment - pensions		489,097
Purchase Accounting Adjustment - pollution control bonds		123,087

Purchase Accounting Adjustment - post retirement		20,328
Purchase Accounting Adjustment - OVEC		2,358,838
Purchase Accounting Adjustment - rent commitment		72,695
Purchase Accounting Adjustment - other		180
Total for Provision for Deferred Income Taxes (410.1)	$	253,017,989

Line 17, Column D:
The balance in Provision for Deferred Income Taxes (410.1) was adjusted due to the purchase of LG&E by PPL in November 2010.
The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$	259,382,206
Purchase Accounting Adjustment - pollution control bonds		20,514
Purchase Accounting Adjustment - rent commitment		11,433
Total for Provision for Deferred Income Taxes (410.1)	$	259,414,153

Line 17, Column E:
The balance in Provision for Deferred Income Taxes (410.1) was adjusted due to the purchase of LG&E by PPL in November 2010.
The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$	159,580,330
Purchase Accounting Adjustment - coal contract		18,801,514
Purchase Accounting Adjustment - emission allowance		2,335,680
Purchase Accounting Adjustment - pensions		391,278
Purchase Accounting Adjustment - pollution control bonds		97,854
Purchase Accounting Adjustment - post retirement		16,262
Purchase Accounting Adjustment - OVEC		2,358,838
Purchase Accounting Adjustment - rent commitment		58,883
Purchase Accounting Adjustment - other		171
Total for Provision for Deferred Income Taxes (410.1)	$	183,640,810

Line 17, Column G:
The balance in Provision for Deferred Income Taxes (410.1) was adjusted due to the purchase of LG&E by PPL in November 2010.
The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$	69,236,240
Purchase Accounting Adjustment - pensions		97,819
Purchase Accounting Adjustment - pollution control bonds		25,233
Purchase Accounting Adjustment - post retirement		4,066
Purchase Accounting Adjustment - rent commitment		13,812
Purchase Accounting Adjustment - other		9
Total for Provision for Deferred Income Taxes (410.1)	$	69,377,179

Line 18, Column C:

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Statement of Income for the Year (Ref Page: 114) - NOTES

The balance in Provision for Deferred Income Taxes (411.1) was adjusted due to the purchase of LG&E by PPL in November 2010.
The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes-Cr. (411.1)		
Without Purchase Accounting	$	174,581,170
Purchase Accounting Adjustment - coal contract		18,801,514
Purchase Accounting Adjustment - emission allowance		2,335,680
Purchase Accounting Adjustment - pensions		489,097
Purchase Accounting Adjustment - pollution control bonds		6,304
Purchase Accounting Adjustment - post retirement		20,328
Purchase Accounting Adjustment - OVEC		2,358,838
Purchase Accounting Adjustment - rent commitment		83,543
Purchase Accounting Adjustment - other		180
Total for Provision for Deferred Income Taxes-Cr. (411.1)	$	198,676,654

Line 18, Column D:
The balance in Provision for Deferred Income Taxes (411.1) was adjusted due to the purchase of LG&E by PPL in November 2010.
The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes-Cr. (411.1)		
Without Purchase Accounting	$	229,345,176
Purchase Accounting Adjustment - pollution control bonds		1,051
Purchase Accounting Adjustment - rent commitment		585
Total for Provision for Deferred Income Taxes-Cr. (411.1)	$	229,346,812

Line 18, Column E
The balance in Provision for Deferred Income Taxes (411.1) was adjusted due to the purchase of LG&E by PPL in November 2010.
The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes-Cr. (411.1)		
Without Purchase Accounting	$	147,464,602
Purchase Accounting Adjustment - coal contract		18,801,514
Purchase Accounting Adjustment - emission allowance		2,335,680
Purchase Accounting Adjustment - pensions		391,278
Purchase Accounting Adjustment - pollution control bonds		5,012
Purchase Accounting Adjustment - post retirement		16,262
Purchase Accounting Adjustment - OVEC		2,358,838
Purchase Accounting Adjustment - rent commitment		67,669
Purchase Accounting Adjustment - other		171
Total for Provision for Deferred Income Taxes-Cr. (411.1)	$	171,441,026

Line 18, Column G
The balance in Provision for Deferred Income Taxes (411.1) was adjusted due to the purchase of LG&E by PPL in November 2010.
The following reflects the purchase accounting adjustment:

Provision for Deferred Income Taxes (411.1) Without Purchase

Accounting	$	27,116,568
Purchase Accounting Adjustment - pensions		97,819
Purchase Accounting Adjustment - pollution control bonds		1,292
Purchase Accounting Adjustment - post retirement		4,066
Purchase Accounting Adjustment - rent commitment		15,874
Purchase Accounting Adjustment - other		9
Total for Provision for Deferred Income Taxes (411.1)	$	27,235,628

Line 39, Column 2:

The balance includes $915,784 unrealized energy trading and risk management derivative contract losses which is attributable to a change in the allocation between Louisville Gas and Electric and Kentucky Utilities Company and due to less activity from buy-backs of positions in 2010. In addition, the balance includes depreciation expense of $103,629 related to plant held for future use.

Line 45, Column 3:

The unrealized gains and losses of $30,550,884 previously recorded in other income and deductions related to the interest rate swaps which were reclassified to a regulatory asset.

Line 58, Column 2:

The balance in Interest on Long-Term Debt (427) was adjusted due to the purchase of LG&E 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	$	38,809,736
Amortization of Purchase Accounting Adjustment		(300,212)
Total for Interest on Long-Term Debt (427)	$	38,509,524

Line 58, Column 3:

The balance in Interest on Long-Term Debt (427) was adjusted due to the purchase of LG&E 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	$	20,574,472
Amortization of Purchase Accounting Adjustment		(50,035)
Total for Interest on Long-Term Debt (427)	$	20,524,437

Statement of Retained Earnings for the Year (Ref Page: 118)

Item (a)	Acct (b)	Amount (c)
UNAPPROPRIATED RETAINED EARNINGS (216)		
State balance and purpose of each appropriated retained earnings amount at end of year and		
1. Balance - Beginning of the Year		$19,093,970.00
Changes (Identify by prescribed retained earnings accounts)		
give accounting entries for any applications of appropriated retained earnings during the year.		
Adjustments to Retained Earnings (439)		
Credit:		
4. TOTAL Credits to Retained Earnings (439)		
Debit:		
5. TOTAL Debits to Retained Earnings (439)		
6. Balance Transferred from Income (433 less 418.1)	0	$124,352,697.00
Appropriations of Retained Earnings (436)		
8. TOTAL appropriations of Retained Earnings (436)		
Dividends Declared - Preferred stock (437)		
10. TOTAL Dividends Declared - Preferred Stock (437)		
Dividends Declared - Common Stock (438)		
	0 Without Par Value	($83,250,000.00)
12. TOTAL Dividends Declared - Common Stock (438)		($83,250,000.00)
13. Transfers from Acct 216.1, Unappropriated Undistributed Subsidary Earnings		

Statement of Retained Earnings for the Year (Ref Page: 118)

Item (a)	Acct (b)	Amount (c)
14. Balance End of Year (Total Lines 1,4,5,6,8,10,12,13)		$60,196,667.00
APPROPRIATED RETAINED EARNINGS (215)		
(215)		
16. TOTAL Appropriated Retained Earnings (215)		
APPROPRIATED RETAINED EARNINGS - AMORTIZATION RESERVE, FEDERAL		
17.TOTAL Appropriated Retained Earnings - Amortization Reserve, Federal (215.1)		
18. TOTAL Appropriated Retained Earnings (total lines 16 and 17) (214,215.1)		
19. TOTAL Retained Earnings (Lines 14 and 18) (215, 215.1, 216)		$60,196,667.00
UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (216.1)		
20. Balance - Beginning of Year (Debit or Credit)		
21. Equity in Earnings for Year (Credit) (418.1)		
22. (Less) Dividends Received (Debit)		
23. Other Charges (explain)		
24. Balance - End of Year		

Note:
The balance in Retained Earnings (215, 215.1, 216) was adjusted due to the purchase of LG&E 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 additional footnotes in hard copy Annual Gas Report.

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22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Statement of Retained Earnings (Ref Page: 118) - NOTES

The following reflects the purchase accounting adjustment:

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$ 868,929,557
Purchase Accounting Adjustment	(808,946,891)
2011 amortization of Purchase Accounting Adjustment - rent commitment (net of deferred taxes of ($10,848))	(17,037)
2010 amortization of Purchase Accounting Adjustment - rent commitment (net of deferred taxes of $10,848)	17,037
2011 amortization of Purchase Accounting Adjustment - pollution control bonds (net of deferred taxes of $116,783)	183,429
2010 amortization of Purchase Accounting Adjustment - pollution control bonds (net of deferred taxes of $19,463)	30,572

Total for Retained Earnings (215,215.1,216)	$ 60,196,667

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Statement of Cash Flows (Ref Page: 120)

	Description	Amounts
1. Net Cash Flow From Operating Activities:		
2. Net Income (Line 72 c on page 117)		$124,352,697.00
3. Noncash Charges (Credits) to Income:		
4. Depreciation and Depletion		$141,998,215.00
Amortization of (Specifiy)		
5.	Plant	$8,133,464.00
6. Deferred Income Taxes (Net)		$56,180,940.00
7. Investment Tax Credit Adjustment (Net)		($2,805,732.00)
8. Net (Increase) Decrease in Receivables		$46,876,509.00
9. Net (Increase) Decrease in Inventory		$20,608,814.00
10. Net (Increase) Decrease in Allowances Inventory		$217.00
11. Net Increase (Decrease) in Payables and Acccrued Expenses		$30,854,794.00
12. Net (Increase) Decrease in Other Regulatory Assets		($52,954,507.00)
13. Net Increase (Decrease) in Other Regulatory Liabilities		$7,191,248.00
14. (Less) Allowance for Other Funds Used During Construction		$0.00
15. (Less) Undistributed Earnings from Subsidiary Companies		$0.00
Other:		
16.	Other	($61,253,932.00)
16.	Change in other deferred debits	$2,071,209.00
16.	Change in other deferred credits	($436,232.00)
17. Net Cash Provided by (Used in) Operating Activities (Total lines 2 thru 16)		$320,817,704.00
Cash Flows from Investment Activities:		
21. Construction and Acquisition of Plant (Including Land):		
22. Gross Additions to Utility Plant (Less nuclear fuel)		($165,322,128.00)
23. Gross Additions to Nuclear Fuel		

Statement of Cash Flows (Ref Page: 120)

Description		Amounts
24. Gross Additions to Common Utility Plant		($14,380,688.00)
25. Gross Additons to Nonutility Plant		
26. (Less) Allowance for Other Funds Used During Construction		
Other		
27.		
Cash Outflows for Plant (Total lines 22-27)		($179,702,816.00)
30. Acquisition of Other Noncurrent Assets (d)		
31. Proceeds from Disposal of Noncurrent Assets (d)		$69,454.00
32. Retirements of Property,Plant and Equipment		
33. Investments in and Advances to Assoc. and Subsidary Companies		
34. Contributions and Advances from Assoc. and Subsidiary Companies		
35. Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
37. Purchase of Investment Securities (a)		
38. Proceeds from Sales of Investment Securities (a)		
40. Loans Made or Purchased		
41. Collections on Loans		
43. Net (Increase) Decrease in Receivables		
44. Net (Increase) Decrease in Inventory		
45. Net (Increase) Decrease in Allowances Held for Speculation		
46. Net Increase (Decrease) in Payables and Accrued Expenses		
Other:		
47.	Reissuance of reacquired pol. control bonds AFS	$163,200,000.00
47.	Costs incurred related to asset rtmnt obligations	($11,759,760.00)
47.	Change in restricted cash	($9,400,674.00)

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Statement of Cash Flows (Ref Page: 120)

Description	Amounts
48. Net Cash Provided by (used in) investing Activities (Lines 28-47)	($37,593,796.00)
Cash Flows from Financing Activities:	
52. Proceeds from Issuance of:	
53. Long - Term Debt (b)	($2,270,371.00)
54. Preferred Stock	
55. Common Stock	
Other	
56	
57. Net Increase in Short-Term Debt (c)	($174,876,000.00)
Other	
58.	
59. Cash Provided by Outside Sources (Total lines 53-58)	($177,146,371.00)
61. Payments for Retirement of	
62. Long-Term Debt (b)	
63. Preferred Stock	
64. Common Stock	
Other	
65.	
66. Net Decrease in Short-Term Debt (c)	
68. Dividends on Preferred Stock	
69. Dividends on Common Stock	($83,250,000.00)
70. Net Cash Provided by (used in) Financing Activities (Lines 59-69)	($260,396,371.00)
Net Increase (Decrease) in Cash and Cash Equivalents (Total Lines 18,49,71)	$22,827,537.00
Cash and Cash Equivalents at Beginning of Year	$2,126,012.00
Cash and Cash Equivalents at End of Year	$24,953,549.00

Statement of Cash Flows (Ref Page: 120) - NOTES

Note:
See detail of Other footnote in hard copy Annual Gas Report.

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Statement of Cash Flows (Ref Page: 120)

Line 16 - Other

Other operating cash flows:

Depreciation charged to balance sheet accounts	$	(63,303,939)
Accumulated Provision for Uncollectible Accounts - Credit		(4,437,227)
Other changes in Net Utility Plant		57,816,038
Amortization of Debt Expenses and Losses on Bonds		3,031,613
Unamortized Discount on Long-Term Debt - Debit		279,860
Net decrease in Prepayments and other assets		854,588
Net increase in Preliminary Survey		(379,275)
Net decreases in Customer Advances for Construction		(1,968,922)
Net increase in Asset Retirement Obligations		5,955,561
Net increase in the Provision for Pension and Postretirement Benefits		34,082,372
Pension and Postretirement Funding		(70,274,658)
Net increase in Change in Non-Hedging Derivatives		1,417,874
Net increase in Other Liabilities		(24,731,049)
Gains and Losses on Interest Rate Swaps		1,679,862
Gains on Disposals of Assets		(69,454)
Proceeds received on the sale of assets		(1,040,785)
Change in Deferred Income Taxes - purchase accounting		105,935
Change in Long-Term Debt - purchase accounting		(300,212)
Change in Miscellaneous Long- Term Liabilities - purchase accounting		27,885
Rounding		1

Total	$	(61,253,932)

Cash and cash equivalents at the end of year is comprised of the following amounts:

Cash (131)	$	24,920,485
Temporary Cash Investments (136)		33,064

Total Cash and Cash Equivalents at the End of Period	$	24,953,549

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Summary of Utility Plant and Accumulated Provisions for Depreciation Amortization and Depletion (Ref Page: 200)

	Total (b)	Electric (c)	Gas (d)	Other (Total)	Common (h)
Utility Plant					
In Service					
3. Plant in Service (Classified)	$4,547,589,659.00	$3,626,363,496.00	$703,277,916.00	$0.00	$217,948,247.00
4. Property under Capital Leases					
5. Plant Purchased or Sold					
6. Completed Construction not Classified	$131,640,892.00	$105,721,872.00	$21,103,199.00	$0.00	$4,815,821.00
7. Experimental Plant Unclassifed					
8. Total - Utility Plant (Lines 3-7)	$4,679,230,551.00	$3,732,085,368.00	$724,381,115.00	$0.00	$222,764,068.00
9. Leased to Others					
10. Held for Future Use	$649,014.00	$649,014.00	$0.00	$0.00	$0.00
11. Construction Work in Progress	$215,276,377.00	$152,710,828.00	$47,481,610.00	$0.00	$15,083,939.00
12. Acquisition Adjustments					
13. Total Utility Plant (Lines 8 - 12)	$4,895,155,942.00	$3,885,445,210.00	$771,862,725.00	$0.00	$237,848,007.00
14. Accum. Prov. for Depr, Amort, And Depl.	$2,117,873,453.00	$1,783,822,898.00	$236,679,884.00	$0.00	$97,370,671.00
15. Net Utility Plant (Line 13 less 14)	$2,777,282,489.00	$2,101,622,312.00	$535,182,841.00	$0.00	$140,477,336.00
16. Detail of Accumulated Provisions for Depreciation Amortization and Depletion					
17. In Service					
18. Depreciation	$2,097,801,848.00	$1,783,822,898.00	$236,679,884.00	$0.00	$77,299,066.00
19. Amort. and Depl. of Production Natural Gas Land and Land Rights					

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Summary of Utility Plant and Accumulated Provisions for Depreciation Amortization and Depletion (Ref Page: 200)

	Total (b)	Electric (c)	Gas (d)	Other (Total)	Common (h)
20. Amort of Underground Storage Land and Land Rights					
21. Amort of Other Utility Plant	$20,071,605.00	$0.00	$0.00	$0.00	$20,071,605.00
22. Total In Service (Lines 18-21)	$2,117,873,453.00	$1,783,822,898.00	$236,679,884.00	$0.00	$97,370,671.00
23. Leased to Others					
24. Depreciation					
25. Amortization and Depletion					
26. Total Leased to Others (Lines 24 and 25)					
27. Held for Future Use					
28. Depreciation					
29. Amortization					
30. Total Held for Future Use (Lines 28 and 29)					
31. Abandonment of Leases (Naturual Gas)					
32. Amort. Of Plant Aquision Adj.					
33. Total Accumulated Provisions (Should agree with Line 14, Total 22,26,30,31 and 32)	$2,117,873,453.00	$1,783,822,898.00	$236,679,884.00	$0.00	$97,370,671.00

Gas Plant in Service - Intangible and Production Plant (Ref Page: 204)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
INTANGIBLE PLANT						
2. Organization (301)						
3. Franchises and Consents (302)	$1,187.00	$0.00	$800.00	$0.00	$0.00	$387.00
4. Miscellaneous Intangible Plant (303)						
5. Total Intangible Plant	$1,187.00	$0.00	$800.00	$0.00	$0.00	$387.00
PRODUCTION PLANT						
7. Natural Gas Production and Gathering Plant						
8. Producing Lands (325.1)						
9. Producing Leaseholds (325.2)						
10. Gas Rights (325.3)						
11. Rights of Way (325.4)						
12. Other Land and Land Rights (325.5)						
13. Gas Well Structures (326)						
14. Field Compressor Station Structures (327)						
15. Field Measuring and Regulating Station Equipment (328)						
16. Other Structures (329)						
17. Producing Gas Wells - Well Construction (330)						
18. Producing Gas Wells - Well Equipment (331)						
19. Field Lines (332)						

Gas Plant in Service - Intangible and Production Plant (Ref Page: 204)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
20. Field Compressor Station Equipment (333)						
21. Field Measuring and Regulating Station Equipment (334)						
22. Drillnig and Cleaning Equipment (335)						
23. Purification Equipment (336)						
24. Other Equipment (337)						
25. Unsuccessful Exploration and Development Costs (338)						
26. Asset Retirement Costs for Natural Gas Production and Gathering Plant (339)						
27. Total Production and Gathering Plant						
28. PRODUCTS EXTRACTION PLANT						
29. Land and Land Rights (340)						
30. Structures and Improvements (341)						
31. Extraction and Refining Equipment (342)						
32. Pipe Lines (343)						
33. Extracted Products Storage Equipment (344)						
34. Compressor Equipment (345)						

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Gas Plant in Service - Intangible and Production Plant (Ref Page: 204)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
35. Gas Measuring and Regulating Equipment (346)						
36. Other Equipment (347)						
37. Asset Retirement Costs for Products Extraction Plant (348)						
38. Total Products Extraction Plant						
39. Total Natural Gas Production Plant (Lines 27 and 38)						
40. Manufactured Gas Production Plant						
41. Total Production Plant (Lines 39 and 40)						

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Gas Plant in Service - Storage and Processing (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
NATURAL GAS STORAGE AND PROCESSING PLANT						
Underground Storage Plant						
44. Land (350.1)	$32,865.00	$0.00	$0.00	$0.00	$0.00	$32,865.00
45. Rights-of-Way (350.2)	$95,613.00	$0.00	$0.00	$0.00	$0.00	$95,613.00
46. Structures and Improvements (351)	$7,595,857.00	$499,468.00	$49,581.00	$0.00	$23,515.00	$8,069,259.00
47. Wells (352)	$11,747,585.00	$577,513.00	$591,626.00	$0.00	$0.00	$11,733,472.00
48. Storage Leaseholds and Rights (352.1)	$548,241.00	$0.00	$0.00	$0.00	$0.00	$548,241.00
49. Reservoirs (352.2)	$400,511.00	$0.00	$0.00	$0.00	$0.00	$400,511.00
50. Non-recoverable Natural Gas (352.3)	$9,648,855.00	$0.00	$0.00	$0.00	$0.00	$9,648,855.00
51. Lines (353)	$14,269,062.00	$782,649.00	$192,991.00	$0.00	$0.00	$14,858,720.00
52. Compressor Station Equipment (354)	$15,737,935.00	$1,041,501.00	$450,121.00	$0.00	$0.00	$16,329,315.00
53. Measuring and Regulating Equipment (355)	$504,695.00	$20,155.00	$0.00	$0.00	$0.00	$524,850.00
54. Purification Equipment (356)	$11,583,755.00	$412,150.00	$22,683.00	$0.00	$0.00	$11,973,222.00
55. Other Equipment (357)	$1,605,184.00	$76,116.00	$2,705.00	$0.00	$0.00	$1,678,595.00
56. Asset Retirement Costs for Underground Storage Plant (358)	$5,596,579.00	$0.00	$395,406.00	$0.00	$0.00	$5,201,173.00
57. Total Underground Storage Plant	$79,366,737.00	$3,409,552.00	$1,705,113.00	$0.00	$23,515.00	$81,094,691.00
Other Storage Plant						

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Gas Plant in Service - Storage and Processing (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
59. Land and Land Rights (360)						
60. Structures and Imporvements (361)						
61. Gas Holders (362)						
62. Purification Equipment (363)						
63. Liquefaction Equipment (363.1)						
64. Vaporaizing Equipment (363.2)						
65. Compressor Equipment (363.3)						
66. Measuring and Regulating equipment (363.4)						
67. Other Equipment (363.5)						
68. Asset Retirement Costs for Other Storage Plant (363.6)						
69. Total Other storage Plant						
70. Base Load Liquefied natural Gas Terminaling and Processing Plant						
71. Land and Land Rights (364.1)						
72. Structures and Improvements (364.2)						
73. LNG Processing Terminal Equipments (364.3)						

Gas Plant in Service - Storage and Processing (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
74. LNG Transportation Equipment (364.4)						
75. Measuring and Regulating Equipment (364.5)						
76. Compressor Station Equipment (364.6)						
77. Communications Equipment (364.7)						
78. Other Equipment (364.8)						
79. Asset Retirement Costs for Base Load Liquefied Natual Gas Terminaliing and Processing Plant (364.9)						
80. Total Base Load Liquefied Nat`l Gas, Terminal and Processing Plant						
76. Total Nat`l Gas Storage and Processing Plant (57,69,80)	$79,366,737.00	$3,409,552.00	$1,705,113.00	$0.00	$23,515.00	$81,094,691.00

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Gas Plant in Service - Transmission,Distribution and General (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
TRANSMISSION PLANT						
83. Land and Land Rights (365.1)						
84. Rights-of-Way (365.2)	$220,660.00	$0.00	$0.00	$0.00	$0.00	$220,660.00
85. Structures and Improvements (366)						
86. Mains (367)	$16,441,210.00	$2,418,397.00	$20,300.00	$0.00	$0.00	$18,839,307.00
87. Compressor Station Equipment (368)						
88. Measuring and Regulating Sstation Equipment (369)						
89. Communication Equipment (370)						
90. Other Equipment (371)						
91. Asset Retirement Costs for Transmission Plant (372)		$3,941,519.00	$0.00	$0.00	$0.00	$3,941,519.00
92. Total Transmission Plant	$16,661,870.00	$6,359,916.00	$20,300.00	$0.00	$0.00	$23,001,486.00
DISTRIBUTION PLANT ( )						
94. Land and Land Rights (374)	$133,742.00	$0.00	$0.00	$0.00	$0.00	$133,742.00
95. Structures and Improvements (375)	$917,416.00	$0.00	$16,952.00	$0.00	$0.00	$900,464.00
96. Mains (376)	$310,864,435.00	$17,384,272.00	$4,156,174.00	$0.00	$0.00	$324,092,533.00
97. Compressor Station Equipment (377)						
98. Measuring and Regulating Station Equipment - General (378)	$10,321,600.00	$2,169,741.00	$53,303.00	$0.00	$0.00	$12,438,038.00

Gas Plant in Service - Transmission,Distribution and General (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
99. Measuring and Regulating Station Equipment - City Gate (379)	$4,173,290.00	$269,601.00	$59,021.00	$0.00	$0.00	$4,383,870.00
100. Services (380)	$176,137,281.00	$17,627,673.00	$135,083.00	$0.00	$0.00	$193,629,871.00
101. Meters (381)	$36,146,392.00	$3,641,942.00	$52,311.00	$0.00	$97,729.00	$39,833,752.00
102. Meter Installations (382)	$0.00					
103. House Regulators (383)	$22,520,447.00	$1,337,995.00	$380,488.00	$0.00	$0.00	$23,477,954.00
104. House Regulator Installations (384)						
105. Industrial Measuring and Regulating Station Equipment (385)	$944,359.00	$0.00	$0.00	$0.00	$0.00	$944,359.00
106. Other Property on Customers Premises (386)						
107. Other Equipment (387)	$51,113.00	$0.00	$0.00	$0.00	$0.00	$51,113.00
108. Asset Retirement Costs for Distribution Plant (388)	$12,009,203.00	$0.00	$77,594.00	$0.00	$0.00	$11,931,609.00
109. Total Distribution Plant	$574,219,278.00	$42,431,224.00	$4,930,926.00	$0.00	$97,729.00	$611,817,305.00
GENERAL PLANT						
111. Land and Land Rights (389)						
112. Structures and Improvements (390)						
113. Office Furniture and Equipment (391)						

Gas Plant in Service - Transmission,Distribution and General (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
114. Transportation Equipment (392)	$2,393,755.00	$205,965.00	$679,875.00	$0.00	($64,613.00)	$1,855,232.00
115. Stores Equipment (393)	$0.00					
116. Tools, Shop and garage Equipment (394)	$4,452,932.00	$208,373.00	$392,581.00	$0.00	($121,244.00)	$4,147,480.00
117. Laboratory Equipment (395)	$0.00					
118. Power Operated Equipment (396)	$2,458,397.00	$428,411.00	$422,274.00	$0.00	$0.00	$2,464,534.00
119. Communication Equipment (397)						
120. Miscellaneous equipment (398)						
121. Subtotal (Lines 104-113)	$9,305,084.00	$842,749.00	$1,494,730.00	$0.00	($185,857.00)	$8,467,246.00
122. Other Tangible Property (399)	$0.00					
123. Asset Retirement Costs for General Plant (399.1)						
124. Total General Plant (Lines 121,122 and 123)	$9,305,084.00	$842,749.00	$1,494,730.00	$0.00	($185,857.00)	$8,467,246.00
125. Total Accounts 101 and 106	$679,554,156.00	$53,043,441.00	$8,151,869.00	$0.00	($64,613.00)	$724,381,115.00
126. Gas Plant Purchased						
127. (Less) Gas Plant Sold	$0.00					
128. Experimental Gas Plant Unclassified						
Total Gas Plant in Service (Lines 125-128)	$679,554,156.00	$53,043,441.00	$8,151,869.00	$0.00	($64,613.00)	$724,381,115.00

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Gas Plant in Service - Transmission,Distribution and General (Ref Page: 206) - NOTES

Note:
Page 206, Line 125, Column f
Transfer of assets among electric, gas and common. $ (64,613)

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Construction Work in Progress - (Acct 107) (Ref Page: 216)

Project (a)	Construction WIP (b)	Est Add Cost
UNDERGROUND STORAGE	$0.00	$0.00
MULDRAUGH-DRILL 5 RECOVERY WELLS	$8,405,166.00	$787,047.00
GAS COMPRESSOR REPLACEMENT/ADDITION	$5,774,791.00	$16,325,640.00
UPGRADE GAS CONTROL SCADA SYSTEM	$1,396,842.00	$0.00
REPLACE PURIFIER #1 REBOILER VESSELS	$873,705.00	$0.00
DRILL HORIZONTAL WELLS IN CENTER GAS STORAGE FIELD	$744,021.00	$16,931.00
INSTALL GATE VALVES	$602,242.00	$144,738.00
UNDERGROUND STORAGE MINOR	$2,977,251.00	$1,159,223.00
0	$0.00	$0.00
TRANSMISSION	$0.00	$0.00
WESTERN KY BLUE & GREEN PIPELINE MODIFICATIONS	$2,339,808.00	$1,537,192.00
WESTERN KY YELLOW PIPELINE MODIFICATIONS	$1,901,136.00	$80,115.00
MAGNOLIA TO PICCADILLY PIPELINE MODIFICATIONS	$1,268,674.00	$1,193,569.00
PENILE TO PADDY'S RUN PIPELINE	$1,198,197.00	$2,597,696.00
REPLACE WESTERN KY YELLOW LINE	$928,602.00	$5,485,398.00
TRANSMISSION MINOR	$1,381,601.00	$261,535.00
0	$0.00	$0.00
DISTRIBUTION	$0.00	$0.00
LARGE SCALE MAIN REPLACEMENTS	$7,961,038.00	$0.00
PRIORITY MAIN REPLACEMENT	$4,526,595.00	$0.00
DISTRIBUTION MINOR	$4,410,036.00	$2,287,369.00
0	$0.00	$0.00
GENERAL PLANT	$0.00	$0.00

Construction Work in Progress - (Acct 107) (Ref Page: 216)

Project (a)	Construction WIP (b)	Est Add Cost
GENERAL PLANT MINOR	$791,905.00	$15,658.00
TOTAL	$47,481,610.00	$31,892,111.00

General Description of Construction Overhead Procedure - Components of Formulat (Ref Page: 218)

	Amount (b)	Capitalization Ration (Percent) (c)	Cost Rate Percentage (d)
Please include all notes requested for construction overhead with the hard copy.			
Uppercase Vars (S,D,P,C,W) fall under Amount (b) column		0	0
Lowercase Vars (s,d,p,c) fall under Cost Rate Percentage (d) column			
1. Components of Formula (Derived from actual book balances and actual cost rates)			
Average Short-Term Debt (Var S)			
Short-Term Interest (Var s)			0
Long Term Debt (Vars D and d)		0	0
Preferred Stock (Vars P and p)		0	0
Common Equity (Vars C and c)		0	0
Total Capitalization			
Average Construction Work in Progress Balance (Var W)		0	0
2. Gross Rate for Borrowed Funds s(S/W) + d[(D/(D+P+C))(1-(S/W)]			
3. Rate for Other Funds [1-(S/W)][p(P/D+P+C)) + c(C/(D+P+C))]			
4. Weighted Average Rate Actually Used for the Year:			
a. Rate for Borrowed Funds			0
b. Rate for Other Funds			0

General Description of Construction Overhead Procedure - Components of Formulat (Ref Page: 218) - NOTES

LOCAL ENGINEERING:

Salaries and expenses of Generation Services Dept., Energy Delivery Dept., and Gas Dept. personnel engaged in construction work, but not assignable to a particular work order (“WO”), are charged to engineering clearing WOs which have been set up in a clearing account for each dept. Examples of such charges are: work with the construction budget; cost of estimating; construction work; preparation of field reports; conferences on construction matters; general supervision of construction projects, etc.

Each month the costs accumulated in these clearing WOs are allocated to specific WOs coming under the direct supervision of the depts. The WOs are spread based on total direct cost of WOs.

The labor and expenses of engineers and foremen who are directly assigned to a particular WO are charged to that WO.

SERVICE CONTRACT CHARGES:

These expenses are charged directly to construction and other projects based on service performed.

EMPLOYEE BENEFITS:

Vacation, holiday, sick and other off-duty payments, hospitalization, dental, group life insurance and pension costs, are charged to construction based on the ratio of direct labor charged to construction to the total direct labor.

ADMINISTRATIVE AND GENERAL EXPENSES:

The allocation of admin and general expenses to construction is based on a study of the estimated time engaged in construction activities by persons and depts. charging time to FERC Acct 920. The admin and general salaries and expenses (FERC Acct 920-921) applicable to construction are allocated to all construction WOs on the basis of total direct costs.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC):

LG&E does not capitalize an AFUDC for gas utility plant.

DISTRIBUTION PROJECTS:
Ongoing long-term projects with additional costs to be incurred and approved on an annual basis.

Note:

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Accumulated Provision for Depreciation of Gas Utility Plant (Acct 108) (Ref Page: 219)

	Description	Total (b)	Gas Plant In Service (c)	Held for Future (d)	Leased (e)
A. BALANCES AND CHANGES DURING YEAR					
Balance beginning of Year		$228,743,331.00	$228,743,331.00	$0.00	$0.00
Depreciation Provisions for Year, Charged to					
Depreciation Expense (403)		$16,244,352.00	$16,244,352.00	$0.00	$0.00
Depreciation Expense for Asset Retirement Costs (403.1)	0	$1,022,857.00	$1,022,857.00	$0.00	
Expense of Gas Plant Leased to Others (413)		$0.00	$0.00	$0.00	$0.00
Transportation Expenses - Clearing		$91,225.00	$91,225.00	$0.00	$0.00
Other Clearing Accounts		$0.00	$0.00	$0.00	$0.00
Other Clearing (Specify)	Accrual for Cost of Removal	$0.00	$0.00	$0.00	$0.00
Other Clearing (Specify)	and Salvage	($19,895.00)	($19,895.00)	$0.00	$0.00
Total Deprec. Prov. for Year		$17,338,539.00	$17,338,539.00	$0.00	$0.00
Net Charges for Plant Retired					
Book Cost of Plant Retired		$8,151,069.00	$8,151,069.00	$0.00	$0.00
Cost of Removal		$1,484,773.00	$1,484,773.00	$0.00	$0.00
Salvage (Credit)		$7,015.00	$7,015.00	$0.00	$0.00
Total Net Chrgs for Plant Ret		$9,628,827.00	$9,628,827.00	$0.00	$0.00
Other Debit or Credit Items (Describe)					
	Reclass cost of removal and	$0.00	$0.00	$0.00	$0.00
	salvage of ARO parent	$0.00	$0.00	$0.00	$0.00
	assets from Other	$0.00	$0.00	$0.00	$0.00
	Regulatory Liabilities	$0.00	$0.00	$0.00	$0.00
	Accumulated Provision	$0.00	$0.00	$0.00	$0.00

Accumulated Provision for Depreciation of Gas Utility Plant (Acct 108) (Ref Page: 219)

Description	Total (b)	Gas Plant In Service (c)	Held for Future (d)	Leased (e)
for Depreciation for	$0.00	$0.00	$0.00	$0.00
settlement of AROs	$258,005.00	$258,005.00	$0.00	$0.00
Customer payments related	$0.00	$0.00	$0.00	$0.00
to construction	$2,703.00	$2,703.00	$0.00	$0.00
Net effect of reserve transfers	$0.00	$0.00	$0.00	$0.00
between functional groups	($33,867.00)	($33,867.00)	$0.00	$0.00
0	$0.00	$0.00	$0.00	$0.00
0	$0.00	$0.00	$0.00	$0.00
0	$0.00	$0.00	$0.00	$0.00
0	$0.00	$0.00	$0.00	$0.00
0	$0.00	$0.00	$0.00	$0.00
0	$0.00	$0.00	$0.00	$0.00
0	$0.00	$0.00	$0.00	$0.00
0	$0.00	$0.00	$0.00	$0.00
0	$0.00	$0.00	$0.00	$0.00
0	$0.00	$0.00	$0.00	$0.00
0	$0.00	$0.00	$0.00	$0.00
0	$0.00	$0.00	$0.00	$0.00
Balance at End of Year	$236,679,884.00	$236,679,884.00	$0.00	$0.00
B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS				
Productions - Manufactured Gas				
Prodcution of Gathering-Natural Gas				
Products Extraction - Natural Gas				

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Accumulated Provision for Depreciation of Gas Utility Plant (Acct 108) (Ref Page: 219)

Description	Total (b)	Gas Plant In Service (c)	Held for Future (d)	Leased (e)
Underground Gas Storage	$30,519,509.00	$30,519,509.00	$0.00	$0.00
Other Storage Plant				
Base Load LNG Terminaling and Processing Plant				
Transmision	$12,211,832.00	$12,211,832.00	$0.00	$0.00
Distribution	$189,160,520.00	$189,160,520.00	$0.00	$0.00
General	$4,788,023.00	$4,788,023.00	$0.00	$0.00
Total	$236,679,884.00	$236,679,884.00	$0.00	$0.00

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Gas Stored Accounts (Lines 1-5) (Ref Page: 220)

	117.1 (b)	117.2 (c)	117.3 (d)	117.4 (e)	164.1 (f)	164.2 (g)	164.3 (h)	Total (I)
Balance at Beginning of Year	$2,139,990.00	$0.00	$0.00	$0.00	$59,956,181.00	$0.00	$0.00	$62,096,171.00
Gas delivered to Storage	$0.00	$0.00	$0.00	$0.00	$55,399,465.00	$0.00	$0.00	$55,399,465.00
Gas Withdrawn from Storage	$0.00	$0.00	$0.00	$0.00	$62,068,040.00	$0.00	$0.00	$62,068,041.00
Other Debits and Credits								
Balance at End of Year	$2,139,990.00	$0.00	$0.00	$0.00	$53,287,604.00	$0.00	$0.00	$55,427,595.00

Note:
Gas Withdrawn from Storage, Column (f) includes $2,229,899 for 461,740 Mcf of gas lost in storage operations charged to Gas Losses (823).

Non-current gas in Column (b) consists of recoverable base gas. Current gas in Column (f) consists of working gas.

The weighted average cost inventory method is used to report gas stored underground.

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Gas Stored Accounts (Lines 6-7) (Ref Page: 220)

	117.1 (b)	117.2 (c)	117.3 (d)	117.4 (e)	164.1 (f)	164.2 (g)	164.3 (h)	Total (I)
MCF	$2,930,000.00	$0.00	$0.00	$0.00	$11,466,101.00	$0.00	$0.00	$14,396,101.00
Amount Per MCF	$0.73	$0.00	$0.00	$0.00	$4.65	$0.00	$0.00	$3.85

Investments (123,124,136) (Ref Page: 222)

	Description of Investment (a)	(b)	Book Cost at Beginning of	Purchases or Additions (d)	Sales of Other Dispositions
Investments in Associated Companies (123)					
(123)					
Other Investments (124)					
(124)					
Temporary Case Investments (136)					
(136)	Goldman Sachs Money Market		$119.71	$0.00	$0.00
(136)	Goldman Sachs Money Market		$174.52	$158,600,000.00	$158,600,000.00
(136)	Fidelity Investments Money Market		$100,111.36	$155,150,000.00	$155,250,000.00
(136)	JP Morgan Funds Money Market		$0.00	$151,456,164.04	$151,456,926.33
(136)	UBS Funds Money Market		$0.00	$137,650,000.00	$137,650,966.15

Investments (123,124,136) (Ref Page: 222) (Part Two)

	Description of Investment (a)	Principal Amt or No of	Book Cost End of Year (g)	Revenues for Year (h)	Gain or Loss (i)
Investments in Associated Companies (123)					
(123)					
Other Investments (124)					
(124)					
Temporary Case Investments (136)					
(136)	Goldman Sachs Money Market	$0.00	$119.71	$0.00	$0.00
(136)	Goldman Sachs Money Market	$0.00	$6,490.17	$6,315.65	$0.00
(136)	Fidelity Investments Money Market	$0.00	$11,238.03	$11,126.67	$0.00
(136)	JP Morgan Funds Money Market	$0.00	$6,164.04	$6,926.33	$0.00
(136)	UBS Funds Money Market	$0.00	$9,052.04	$10,018.19	$0.00

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Investments in Subsidiary Companies (123.1) (Ref Page: 224)

	Description	Date Acquired (b)	Date Maturity (c)	Investment Beg of Yr. (d)	Equity in Subsidiary (e)	Revenues (f)	Investment End Yr (g)	Invest Disposed of (h)
	Ohio Valley Electric Corporation (5.63%)			$0.00	$0.00	$56,300.00	$0.00	$0.00
	Common Stock $100 par value, 5,630 shares			$0.00	$0.00	$0.00	$0.00	$0.00
	700 shares	11/18/1952		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	700 shares	01/08/1953		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	700 shares	02/25/1953		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	700 shares	04/10/1953		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	700 shares	05/12/1953		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	1,400 shares	07/27/1953		$140,000.00	$0.00	$0.00	$140,000.00	$0.00
	730 shares	03/04/2005		$104,286.00	$0.00	$0.00	$104,286.00	$0.00
TOTAL				$594,286.00	$0.00	$56,300.00	$594,286.00	$0.00

Note:
See Note 1 of Notes to Financial Statements under Cost Method Investment for a full description of the Ohio Valley Electric Company investment.

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Prepayments (Ref Page: 230)

	Balance at End of Year
Prepaid Insurance	$2,700,568.00
Prepaid Rents	$0.00
Prepaid Taxes	$977,319.00
Prepaid Interest	$0.00
Miscellaneous Prepayments	$1,794,466.00
Total	$5,472,353.00

Note:
The Miscellaneous Prepayments line is comprised of Southwest Power Pool $609,600, Tennessee Valley Authority $390,144, Gas for Combustion Turbines $297,141, Rights of Way $226,667, Ventyx $104,132, Risk Management $90,000, Ascend Analytics $30,781, Technical Innovation, LLC $25,809, Vehicle License $17,716, Powerline Systems Inc. $2,214 and Primate Technologies, Inc. $262.

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Extraordinary Property Losses (182.1) (Ref Page: 230)

	Description	Balance Beg Yr (b)	Total Loss (b)	Losses During Yr	Acct (d)	Written Off (e)	Balance (f)
	0	$0.00	$0.00	$0.00	0	$0.00	$0.00
TOTAL		$0.00	$0.00		0	$0.00	$0.00

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Unrecovered Plant and Regulatory Study costs (182.2) (Ref Page: 230)

Description	Balance Beg Yr (b)	Total Loss (b)	Losses During Yr	Acct (d)	Written Off (e)	Balance (f)
0	$0.00	$0.00	$0.00	0	$0.00	$0.00
TOTAL	$0.00	$0.00			$0.00	$0.00

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Other Regulatory Assets (Acct 182.3) (Ref Page: 232)

Description and Purpose	Bal Beg Yr (b)	Debits (c)	Written Off Acct (d)	Written Off Amt (e)	Balance End Yr (f)
ASC 715 - Pension and Postretirement	$213,180,670.00	$12,124,492.00	0	$0.00	$225,305,162.00
Asset Retirement Obligation - Electric	$6,587,791.00	$4,030,312.00	108/230	$1,194,570.00	$9,423,533.00
Wind Storm 2008 (Aug-10 to Jul-20)	$22,559,486.00	$0.00	593	$2,354,034.00	$20,205,452.00
ASC 740 - Income Taxes	$0.00	$15,035,797.00	282/283	$305,663.00	$14,730,134.00
MISO Exit Fee (Mar-09 to Feb-14)	$1,509,467.00	$0.00	575.7	$749,834.00	$759,633.00
Asset Retirement Obligation - Gas	$250,046.00	$2,032,870.00	230	$1,048,996.00	$1,233,920.00
Asset Retirement Obligation - Common	$1,275.00	$7,832.00	0	$0.00	$9,107.00
KY Consortium for Carbon Storage (Aug-10 toJul-14)	$786,578.00	$0.00	930.2	$219,511.00	$567,067.00
Winter Storm 2009-Electric/Gas (Aug-10 to Jul-20)	$42,011,791.00	$0.00	571/593/880	$4,383,839.00	$37,627,952.00
Environmental Cost Recovery	$4,720,309.00	$1,046,099.00	440-445	$5,766,408.00	$0.00
Performance-Based Rates	$2,434,953.00	$3,438,719.00	495/803	$1,855,580.00	$4,018,092.00
EKPC FERC Transmission Costs (Mar-09 to Feb-14)	$536,979.00	$0.00	456/566	$169,572.00	$367,407.00
Rate Case Expenses - Electric (Mar-09 to Feb-12)	$289,050.00	$0.00	928	$247,757.00	$41,293.00
Rate Case Expenses - Gas (Mar-09 to Feb-12)	$96,825.00	$0.00	928	$82,993.00	$13,832.00
Carbon Mgmt Research Group (Aug-10 to Jul-20)	$154,470.00	$97,560.00	930.2	$97,560.00	$154,470.00
Fuel Adjustment Clause	$3,191,000.00	$5,497,000.00	440-445	$5,090,000.00	$3,598,000.00
Gas Supply Clause	$1,112,017.00	$4,994,730.00	254/803	$4,423,367.00	$1,683,380.00

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Other Regulatory Assets (Acct 182.3) (Ref Page: 232)

	Description and Purpose	Bal Beg Yr (b)	Debits (c)	Written Off Acct (d)	Written Off Amt (e)	Balance End Yr (f)
	Long-Term Interest Rate Swap	$34,281,361.00	$35,186,478.00	244/245	$9,901,375.00	$59,566,464.00
	Coal Contracts (Nov-10 to Dec-15)	$9,214,861.00	$0.00	253	$4,282,428.00	$4,932,433.00
	Swap Termination (Aug-10 to Apr-35)	$9,195,698.00	$0.00	930.2	$258,476.00	$8,937,222.00
	Corporate Headquarters Lease (Nov-10 to Jul-15)	$794,713.00	$0.00	253/931	$195,193.00	$599,520.00
	Rate Case Expenses - Electric (Aug-10 to Jul-13)	$722,898.00	$0.00	928	$279,832.00	$443,066.00
	Rate Case Expenses - Gas (Aug-10 to Jul-13)	$413,700.00	$0.00	928	$160,142.00	$253,558.00
	Unamortized Debt Expense (various)	$3,667,742.00	$0.00	181	$186,561.00	$3,481,181.00
	Summer Storm 2011	$0.00	$8,052,145.00	580	$20.00	$8,052,125.00
	General Management Audit - Electric		$90,545.00	0	$0.00	$90,545.00
	General Management Audit - Gas		$29,487.00	0	$0.00	$29,487.00
Total		$357,713,680.00	$91,664,066.00		$43,253,711.00	$406,124,035.00

Note:
ASC 740 Income Taxes, Column c
The regulatory assets represent the future revenue impact from the reversal of deferred income tax liability required for a tax depreciation basis adjustment.

See additional footnotes in hard copy Annual Gas Report.

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Other Regulatory Assets (Acct 182.3) (Ref Page: 232) - NOTES

Coal Contracts (Nov-10 to Dec-15), Column f:

The balance was adjusted due to the purchase of LG&E 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		11,265,929
2011 Amortization of Purchase Accounting Adjustment		(4,282,428)
2010 Amortization of Purchase Accounting Adjustment		(2,051,068)
Total for Coal Contracts (Nov-10 to Dec-15)	$	4,932,433

Corporate Headquarters Lease (Nov-10 to Jul-15), Column f:

The balance was adjusted due to the purchase of LG&E 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 Purchase Accounting	$	-
Purchase Accounting Adjustment		794,713
2011 Amortization of Purchase Accounting Adjustment		(195,193)
Total for Corporate Headquarters Lease (Nov-10 to Jul-15)	$	599,520

Unamortized Debt Expense, Column f:

The balance represents the reclassification from Unamortized Debt Expense (various) due to the purchase of LG&E by PPL in November 2010, as these costs are considered to have no fair value in purchase accounting under US GAAP. However, LG&E 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		3,698,836
2011 Amortization of Purchase Accounting Adjustment		(186,562)
2010 Amortization of Purchase Accounting Adjustment		(31,094)
Rounding		1
Total for Unamortized Debt Expense (various)	$	3,481,181

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Miscellaneous Deferred Debits (Acct 186) (Ref Page: 233)

	Description (a)	Bal Beg Yr (b)	Debits (c)	CR Acct (d)	CR Amt (e)	Bal End Yr (c)
	Goodwill	$389,157,352.00	$0.00	0	$0.00	$389,157,352.00
	OVEC Power Purchase Contract (Nov-10 to Mar-26)	$85,809,209.00	$0.00	254	$5,472,941.00	$80,336,268.00
	Coal Contracts (Nov-10 to Dec-16)	$117,659,961.00	$0.00	254	$39,340,574.00	$78,319,387.00
	Valuation of SO2 Allowances (Nov-10 to Dec-40)	$3,026,064.00	$0.00	254	$1,011,877.00	$2,014,187.00
	Valuation of NOx Ozone Allow. (Nov-10 to Dec-11)	$226,663.00	$0.00	254	$226,663.00	$0.00
	Valuation of NOx Annual Allow. (Nov-10 to Dec-11)	$4,180,673.00	$0.00	254	$4,180,673.00	$0.00
	Customer Credit Accounts Receivable	$69,519.00	$804,935.00	142/193	$426,403.00	$448,051.00
	Financing Expense	$166,704.00	$2,101,853.00	181/189/232	$2,242,970.00	$25,587.00
	Cellular Antenna Billable Charges	$34,666.00	$223,483.00	143/456	$258,149.00	$0.00
	Land Options	$4,138.00	$0.00	921	$4,138.00	$0.00
	Rounding	($2.00)	$2.00	0	$0.00	$0.00
Misc. Work in Progress		$0.00	$0.00		$0.00	$0.00
Total		$600,334,947.00	$3,130,273.00		$53,164,388.00	$550,300,832.00

Miscellaneous Deferred Debits (Acct 186) (Ref Page: 233) - NOTES

Goodwill, Column Bal End Yr (c):
The Goodwill balance of 389,157,352 represents Louisville Gas and Electric Company's franchise value as a result of the acquisition by PPL Corporation in November 2010 which are attributed to the going concern of the business.

OVEC Power Purchase Contract (Nov-10 to Mar-26), Column Bal End Yr (c):
The balance of $80,336,268 relates to the fair measurement of $86,856,705 for the power purchase contract 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.

Coal Contracts (Nov-10 to Dec-16), Column Bal End Yr (c):
The balance of $78,319,387 relates to the fair value measurement of $123,813,249 for Louisville Gas and Electric'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.

Valuation of SO2 Allowances (Nov-10 to Dec-40), Column Bal End Yr (c):
The balance of $2,014,187 relates to the fair value measurement of $3,219,107 for LG&E'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.

Note:

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Accumulated Deferred Income Taxes (Acct 190) (Ref Page: 234)

Description	Bal Beg Yr	Amt 410.1 (c)	Amt 411.1 (d)	Amt 410.2 (e)	Amt 411.2 (f)
Account 190					
Electric	$114,994,498.00	$50,895,347.00	$10,880,269.00	$0.00	$0.00
Gas	$11,649,354.00	$12,702,861.00	$3,180,301.00	$0.00	$0.00
Other (Define)	$563,530.00	$0.00	$0.00	$139,696.00	$314,388.00
Total	$127,207,382.00	$63,598,208.00	$14,060,570.00	$139,696.00	$314,388.00
Other (Specify)					
TOTAL Acct 190	$127,207,382.00	$63,598,208.00	$14,060,570.00	$139,696.00	$314,388.00
Classification of TOTAL					
Federal INcome TAx	$106,625,489.00	$54,372,709.00	$12,259,261.00	$126,219.00	$273,964.00
State Income Tax	$20,581,893.00	$9,225,499.00	$1,801,309.00	$13,477.00	$40,424.00
Local Income Tax					

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Accumulated Deferred Income Taxes (Acct 190) (Ref Page: 234) (Part Two)

Description	Debit Adj Acct (g)	Debit Amount (h)	Credit Acct (i)	Credit Amount (j)	Balance End Yr (k)
Account 190					
Electric	254/282	$13,070,458.00		$0.00	$88,049,878.00
Gas		$0.00	254	$14,227.00	$2,112,567.00
Other (Define)		$0.00		$0.00	$738,222.00
Total		$13,070,458.00		$14,227.00	$90,900,667.00
Other (Specify)					
TOTAL Acct 190		$13,070,458.00		$14,227.00	$90,900,667.00
Classification of TOTAL					
Federal INcome TAx		$11,102,863.00		$12,032.00	$75,750,617.00
State Income Tax		$1,967,595.00		$2,195.00	$15,150,050.00
Local Income Tax					

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Capital Stock (Accounts 201 and 204) (Ref Page: 250)

	Class, Series and Name of	Num Shares Auth (b)	Par or Stated Val (c)	Call Price (d)	Outstanding Shares (e)
Common Stock					
	Without Par Value	75,000,000	$0.00	$0.00	$21,294,223.00
Total Common Stock		75,000,000	$0.00	$0.00	$21,294,223.00
Preferred Stock					
	$25 Par Value	1,720,000	$0.00	$0.00	$0.00
	Without Par Value	6,750,000	$0.00	$0.00	$0.00
Total Preferred Stock		8,470,000	$0.00	$0.00	$0.00
TOTAL Capital Stock		83,470,000	$0.00	$0.00	$21,294,223.00
Other					

Capital Stock (Accounts 201 and 204) (Ref Page: 250) (Part Two)

	Class, Series and Name	Outstanding Amt (f)	Num Held Rqd 217 (g)	Cost Held Rqd 217 (h)	Num Held Sinking (i)	Num Held Amount (j)
Common Stock						
	Without Par Value	$425,170,424.00	0	$0.00	0	$0.00
Total Common Stock		$425,170,424.00	0	$0.00	0	$0.00
Preferred Stock						
	$25 Par Value	$0.00	0	$0.00	0	$0.00
	Without Par Value	$0.00	0	$0.00	0	$0.00
Total Preferred Stock		$0.00	0	$0.00	0	$0.00
TOTAL Capital Stock		$425,170,424.00	0	$0.00	0	$0.00
Other						

Note:
No shares of Preferred Stock remain issued or outstanding.

There is no Call Price for Common Stock, Without Par Value.

The Common Stock of Louisville Gas and Electric Company is owned by its parent company, LG&E and KU Energy LLC.

Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Page: 252)

Description (a)	* (b)	Shares (c)	Amount (d)
Capital Stock Subscribed (202,205)			
Not applicable for LG&E		0	$0.00
Total Capital Stock Subscribed			
Stock Liability for Conversion (203,206)			
Not applicable for LG&E		0	$0.00
Total Stock Liability for Conversion			
Premium on Capital Stock (207)			
Not applicable for LG&E		0	$0.00
Total Premium on Capital Stock (207)			
Installments Received on Capital Stock (212)			
Not applicable for LG&E		0	$0.00
Total Installments Received on Capital Stock (212)			

Other Paid-In Capital (208-211) (Ref Page: 253)

Item (a)		Amount (b)
(a) Donations Received from Stockholders (208)		
Total (208)		
(b) Reduction in Par or Stated Value (209)		
Total (209)		
(c) Gain or Resale or Cancellation of Reacquired Capital Stock (210)		
Total (210)		
(d) Miscellaneous Paid-In Capital (211)		
	Contributed Capital	$1,277,667,368.00
Total (211)		$1,277,667,368.00
Total Accts 208-211		$1,277,667,368.00

Note:
The balance in Other Paid-in Capital (208-211) was adjusted due to the purchase of LG&E by PPL in November 2010. To reflect the fair value, the balance was adjusted for the fixed rate pollution control bonds net of deferred taxes and goodwill. The balance also includes elimination of Retained Earnings (215, 215.1, 216) at October 31, 2010.

See additional footnotes in hard copy Annual Gas Report.

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Other Paid-in Capital (Ref Page: 253) - NOTES

The following reflects the purchase accounting adjustment:

Other Paid-in Capital (208-211) Without Purchase Accounting	$ 83,581,499
Purchase Accounting Adjustment - fixed rate pollution control bonds	(4,018,374)
Purchase Accounting Adjustment - goodwill	389,157,352
Purchase Accounting Adjustment - prior retained earnings	808,946,891
Total Purchase Accounting Adjustments	1,194,085,869
Balance - End of Period Total for Other Paid-in Capital (208-211) Purchase Accounting	$ 1,277,667,368

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Discount on Capital Stock (Act 213) (Ref Page: 254)

Class and Series (a)	Balance End Yr (b)
Not applicable for LG&E	0.0000
TOTAL	

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Capital Stock Expense (Act 214) (Ref Page: 254)

Class and Series (a)	Balance End Yr (b)
Expenses on Common Stock	$835,889.00
TOTAL	$835,889.00

Long-Term Debt (221,222,223 and 224) (Ref Page: 256)

	Class Series and Name (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (d)	Interest Rate in % (e)
Acct 221 Bonds					
(221)	Pollution Control Bonds: (2)			$0.00	0.0000
(221)	Jefferson Co 2000 Series A, due 5/1/2027, Var	05/19/2000	05/01/2027	$25,000,000.00	0.0000
(221)	Trimble Co 2000 Series A, due 8/1/2030, Var	08/01/2000	08/01/2030	$83,335,000.00	0.0000
(221)	Jefferson Co 2001 Series A, due 9/1/2027, Var	09/11/2001	09/01/2027	$10,104,000.00	0.0000
(221)	Jefferson Co 2001 Series A, due 9/1/2026, Var	03/06/2002	09/01/2026	$22,500,000.00	0.0000
(221)	Trimble Co 2001 Series A, due 9/1/2026, Var	03/06/2002	09/01/2026	$27,500,000.00	0.0000
(221)	Jefferson Co 2001 Series B, due 11/1/2027, Var	03/22/2002	11/01/2027	$35,000,000.00	0.0000
(221)	Trimble Co 2001 Series B, due 11/1/2027, Var	03/22/2002	11/01/2027	$35,000,000.00	0.0000
(221)	Trimble Co 2002 Series A, due 10/1/2032, Var	10/15/2002	10/01/2032	$41,665,000.00	0.0000
(221)	Louisville Metro 2003 Series A, due 10/1/2033,1.9%	11/20/2003	10/01/2033	$128,000,000.00	1.9000
(221)	Louisville Metro 2005 Series A,due 2/1/2035,5.75%	04/13/2005	02/01/2035	$40,000,000.00	5.7500
(221)	Trimble Co 2007 Series A,due 6/1/2033, 4.600%	04/26/2007	06/01/2033	$60,000,000.00	4.6000
(221)	Louisville Metro 2007 Series A,due 6/1/2033,5.625%	04/26/2007	06/01/2033	$31,000,000.00	5.6250
(221)	Louisville Metro 2007 Series B, due 6/1/2033, 1.9%	04/26/2007	06/01/2033	$35,200,000.00	1.9000
(221)	Interest Rate Swaps (3)			$0.00	0.0000
(221)	First Mortgage Bonds: (4)			$0.00	0.0000
(221)	2010 due 11/15/2015, 1.625%	11/16/2010	11/15/2015	$250,000,000.00	1.6250

Long-Term Debt (221,222,223 and 224) (Ref Page: 256) (Part Two)

	Class Series and Name (a)	Interest Amount (f)	Held - Reaquired Bonds	Held - Sinking and Other	Redemption Price Per $100
Acct 221 Bonds					
(221)	Pollution Control Bonds: (2)	$0.00	$0.00	$0.00	$0.00
(221)	Jefferson Co 2000 Series A, due 5/1/2027, Var	$1,249,667.00	$0.00	$0.00	$0.00
(221)	Trimble Co 2000 Series A, due 8/1/2030, Var	$190,872.00	$0.00	$0.00	$0.00
(221)	Jefferson Co 2001 Series A, due 9/1/2027, Var	$19,063.00	$0.00	$0.00	$0.00
(221)	Jefferson Co 2001 Series A, due 9/1/2026, Var	$166,740.00	$0.00	$0.00	$0.00
(221)	Trimble Co 2001 Series A, due 9/1/2026, Var	$98,533.00	$0.00	$0.00	$0.00
(221)	Jefferson Co 2001 Series B, due 11/1/2027, Var	$272,312.00	$0.00	$0.00	$0.00
(221)	Trimble Co 2001 Series B, due 11/1/2027, Var	$270,890.00	$0.00	$0.00	$0.00
(221)	Trimble Co 2002 Series A, due 10/1/2032, Var	$112,135.00	$0.00	$0.00	$0.00
(221)	Louisville Metro 2003 Series A, due 10/1/2033,1.9%	$2,364,820.00	$0.00	$0.00	$0.00
(221)	Louisville Metro 2005 Series A,due 2/1/2035,5.75%	$2,300,000.00	$0.00	$0.00	$0.00
(221)	Trimble Co 2007 Series A,due 6/1/2033, 4.600%	$2,760,000.00	$0.00	$0.00	$0.00
(221)	Louisville Metro 2007 Series A,due 6/1/2033,5.625%	$1,743,750.00	$0.00	$0.00	$0.00
(221)	Louisville Metro 2007 Series B, due 6/1/2033, 1.9%	$652,820.00	$0.00	$0.00	$0.00
(221)	Interest Rate Swaps (3)	$7,772,722.00	$0.00	$0.00	$0.00
(221)	First Mortgage Bonds: (4)	$0.00	$0.00	$0.00	$0.00

Long-Term Debt (221,222,223 and 224) (Ref Page: 256)

	Class Series and Name (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (d)	Interest Rate in % (e)
(221)	2010 due 11/15/2040, 5.125%	11/16/2010	11/15/2040	$285,000,000.00	5.1250
Total (221)				$1,109,304,000.00	
Acct 222 Reacquired Bonds					
(222)	Reacquired Bonds(5)			$0.00	0.0000
(222)	Louisville Metro 2003 Series A, due 10/1/2033, Var	11/20/2003	10/01/2033	$0.00	0.0000
(222)	Louisville Metro 2007 Series B, due 6/1/2033, Var	04/26/2007	06/01/2033	$0.00	0.0000
Total (222)				$0.00	
Acct 223 Advances from Associated Companies					
(223)					0
Total (223)					
Acct 224 Other Long Term Debt					
(224)	Purchase Accounting Adjustments for Fair			$0.00	0.0000
(224)	Value Measurement(7)			$0.00	0.0000
(224)	Louisville Metro 2007 Series A,due 6/1/2033,5.625%			$2,562,479.00	5.6250
(224)	Trimble Co 2007 Series A, due 6/1/2033,4.600%			($1,956,108.00)	4.6000
(224)	Jefferson Co 2000 Series A, due 5/1/2027,5.375%			$1,298,338.00	5.3750
(224)	Louisville Metro 2005 Series A,due 2/1/2035,5.750%			$4,321,761.00	5.7500
Total (224)				$6,226,470.00	

Long-Term Debt (221,222,223 and 224) (Ref Page: 256) (Part Two)

	Class Series and Name (a)	Interest Amount (f)	Held - Reaquired Bonds	Held - Sinking and Other	Redemption Price Per $100
(221)	2010 due 11/15/2015, 1.625%	$4,062,500.00	$0.00	$0.00	$0.00
(221)	2010 due 11/15/2040, 5.125%	$14,606,250.00	$0.00	$0.00	$0.00
Total (221)		$38,643,074.00	$0.00	$0.00	$0.00
Acct 222 Reacquired Bonds					
(222)	Reacquired Bonds(5)	$0.00	$0.00	$0.00	$0.00
(222)	Louisville Metro 2003 Series A, due 10/1/2033, Var	($13,887.00)	$0.00	$0.00	$0.00
(222)	Louisville Metro 2007 Series B, due 6/1/2033, Var	($4,456.00)	$0.00	$0.00	$0.00
Total (222)		($18,343.00)	$0.00	$0.00	$0.00
Acct 223 Advances from Associated Companies					
(223)					
Total (223)					
Acct 224 Other Long Term Debt					
(224)	Purchase Accounting Adjustments for Fair	$0.00	$0.00	$0.00	$0.00
(224)	Value Measurement(7)	$0.00	$0.00	$0.00	$0.00
(224)	Louisville Metro 2007 Series A,due 6/1/2033,5.625%	($119,649.00)	$0.00	$0.00	$0.00
(224)	Trimble Co 2007 Series A, due 6/1/2033,4.600%	$91,336.00	$0.00	$0.00	$0.00
(224)	Jefferson Co 2000 Series A, due 5/1/2027,5.375%	($84,675.00)	$0.00	$0.00	$0.00
(224)	Louisville Metro 2005 Series A,due 2/1/2035,5.750%	($187,224.00)	$0.00	$0.00	$0.00
Total (224)		($300,212.00)	$0.00	$0.00	$0.00

Long-Term Debt (221,222,223 and 224) (Ref Page: 256) (Part Two) - NOTES

Note:
(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 Louisville Gas and Electric Company (LG&E) issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates LG&E 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) As of December 31, 2011, the company had in effect four interest-rate swap agreements to hedge its exposure to tax exempt rates related to Pollution Control Bonds, Variable Rate Series. The Company's positions under the swap agreements are to pay a fixed rate and receive a variable rate based on the Bond Market Association Municipal Swap Index or London Interbank Offered Rate (LIBOR). The specifics for each swap agreement related to notional amounts, maturity dates, payable and receivable positions are as follows:

Notional Amount Maturity Payable Receivable
$83,335,000 11/01/2020 Fixed 5.495% BMA Index
$32,000,000 10/01/2033 Fixed 3.657% 68% of 1 mo LIBOR
$32,000,000 10/01/2033 Fixed 3.645% 68% of 1 mo LIBOR
$32,000,000 10/01/2033 Fixed 3.695% 68% of 1 mo LIBOR

(4) In November 2010, LG&E requested and was granted, authorization to issue first mortgage bonds totaling $535 million by the Kentucky Public Service Commission in its September 30, 2010, Order in Case No. 2010-00205. 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.

See additional footnotes in hard copy Annual Gas Report.

Long-Term Debt (221, 222, 223 and 224) (Ref Page: 256)

(4) (cont.) In April 2011, LG&E 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.

(5) As of December 31, 2011, LG&E had no remaining repurchased bonds.

(6) 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 estimated 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
Louisville Metro 2007 Series A, due 6/1/2033, 5.625%	$ 31,000,000	$ 4,540,189	$ 35,540,189
Trimble County 2007 Series A, due 6/1/2033, 4.600%	$ 60,000,000	$ (2,062,667)	$ 57,937,333
Jefferson County 2000 Series A, due 5/1/2027, 5.375%	$ 25,000,000	$ 2,702,070	$ 27,702,070
Louisville Metro 2005 Series A, due 2/1/2035, 5.750%	$ 40,000,000	$ 1,397,125	$ 41,397,125

The purchase accounting adjustments were recorded to Other Long-Term Debt Account (224) and are being amortized over the lives of the related issues to Interest on Long-Term Debt Account (427).

Line 1, Column I:

Interest on Bonds and Revolving Credit: (221/222/224/231):	
Total Account (221)	$ 38,643,074
Total Account (222)	(18,343)
Total Account (224)	(300,212)
Interest on Long-Term Debt	38,324,519
Notes Payable (231)	185,005
Total Interest on Long-Term Debt (427)	$ 38,509,524
Interest on Advances to Associated Companies (223):	
Advances to Associated Companies (223)	$ -
Other Short Term Interest	9,663
Total Account (430)	$ 9,663

Unamortized Debt Expense (181,225,226) (Ref Page: 258)

	Designation of Long-Term	Principal Amount of Debt	Total Expense Premium or	Amortization Period From (d)	Amortization Period To (e)
Acct 181					
(181)	Unamortized Debt Expense	$0.00	$0.00		
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)	Jefferson County 2001 Series A, due 9/1/2027, Var	$10,104,000.00	$526,084.00	09/11/2001	09/01/2027
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)	Trimble County 2000 Series A, due 8/1/2030, Var	$83,335,000.00	$1,154,826.00	08/01/2000	08/01/2030
(181)	Jefferson County 2001 Series A, due 9/1/2026, Var	$22,500,000.00	$242,653.00	03/06/2002	09/01/2026
(181)	Trimble County 2001 Series A, due 9/1/1/2026, Var	$27,500,000.00	$263,855.00	03/06/2002	09/01/2026
(181)	Jefferson County 2001 Series B, due 11/1/2027, Var	$35,000,000.00	$281,244.00	03/22/2002	11/01/2027
(181)	Trimble County 2001 Series B, due 11/1/2027, Var	$35,000,000.00	$281,283.00	03/22/2002	11/01/2027
(181)	Trimble County 2002 Series A, due 10/1/2032, Var	$41,665,000.00	$1,112,006.00	10/15/2002	10/01/2032
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)	Trimble County 2007 Series A, due 6/1/2033, 4.600%	$60,000,000.00	$1,239,280.00	04/26/2007	06/01/2033
(181)	FMB 2010 due 11/15/2015, 1.625%	$250,000,000.00	$2,563,689.00	11/16/2010	11/15/2015

Unamortized Debt Expense (181,225,226) (Ref Page: 258) (Part Two)

	Designation of Long-Term	Beginning of Year (f)	Debits (g)	Credits (h)	Balance End of Year (i)
Acct 181					
(181)	Unamortized Debt Expense	$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)	Jefferson County 2001 Series A, due 9/1/2027, Var	$339,875.00	$0.00	$20,393.00	$319,482.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)	Trimble County 2000 Series A, due 8/1/2030, Var	$758,019.00	$0.00	$38,707.00	$719,312.00
(181)	Jefferson County 2001 Series A, due 9/1/2026, Var	$155,472.00	$0.00	$9,923.00	$145,549.00
(181)	Trimble County 2001 Series A, due 9/1/1/2026, Var	$169,043.00	$0.00	$10,790.00	$158,253.00
(181)	Jefferson County 2001 Series B, due 11/1/2027, Var	$185,087.00	$0.00	$10,995.00	$174,092.00
(181)	Trimble County 2001 Series B, due 11/1/2027, Var	$185,117.00	$0.00	$10,997.00	$174,120.00
(181)	Trimble County 2002 Series A, due 10/1/2032, Var	$809,566.00	$0.00	$37,222.00	$772,344.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)	Trimble County 2007 Series A, due 6/1/2033, 4.600%	$1,065,563.00	$0.00	$47,534.00	$1,018,029.00
(181)	FMB 2010 due 11/15/2015, 1.625%	$2,165,099.00	$348,214.00	$493,513.00	$2,019,800.00

Unamortized Debt Expense (181,225,226) (Ref Page: 258)

	Designation of Long-Term	Principal Amount of Debt	Total Expense Premium or	Amortization Period From (d)	Amortization Period To (e)
(181)	FMB 2010 due 11/15/2040, 5.125%	$285,000,000.00	$3,570,026.00	11/16/2010	11/15/2040
(181)	Revolving Credit Facility	$0.00	$4,950,103.00	11/01/2010	12/31/2014
(181)	Purchase Accounting Adjustment	$0.00	($3,698,836.00)	11/01/2010	12/31/2014
(181)	Louisville Metro 2003 Series A, due 10/1/2033, 1.9	$128,000,000.00	$451,724.00	01/31/2011	10/01/2033
(181)	Louisville Metro 2007 Series B, due 6/1/2033, 1.9%	$35,200,000.00	$173,150.00	01/31/2011	06/01/2033
Total (181)		$1,013,304,000.00	$13,111,087.00		
Acct 225					
(225)					
Total (225)		$0.00	$0.00		
Acct 226					
(226)	Unamortized Debt Discount	$0.00	$0.00		
(226)	FMB 2010 due 11/15/2015, 1.625%	$250,000,000.00	$882,500.00	11/16/2010	11/15/2015
(226)	FMB 2010 due 11/15/2040, 5.125%	$285,000,000.00	$3,100,800.00	11/16/2010	11/15/2040
Total (226)		$535,000,000.00	$3,983,300.00		

Unamortized Debt Expense (181,225,226) (Ref Page: 258) (Part Two)

	Designation of Long-Term	Beginning of Year (f)	Debits (g)	Credits (h)	Balance End of Year (i)
(181)	FMB 2010 due 11/15/2040, 5.125%	$3,196,713.00	$360,801.00	$114,852.00	$3,442,662.00
(181)	Revolving Credit Facility	$4,087,097.00	$693,921.00	$997,096.00	$3,783,922.00
(181)	Purchase Accounting Adjustment	($3,667,742.00)	$186,561.00	$0.00	($3,481,181.00)
(181)	Louisville Metro 2003 Series A, due 10/1/2033, 1.9		$451,725.00	$19,193.00	$432,532.00
(181)	Louisville Metro 2007 Series B, due 6/1/2033, 1.9%		$173,150.00	$7,051.00	$166,099.00
Total (181)		$9,448,909.00	$2,214,372.00	$1,818,266.00	$9,845,015.00
Acct 225					
(225)					
Total (225)			$0.00	$0.00	$0.00
Acct 226					
(226)	Unamortized Debt Discount	$0.00	$0.00	$0.00	$0.00
(226)	FMB 2010 due 11/15/2015, 1.625%	$860,438.00	$0.00	$176,500.00	$683,938.00
(226)	FMB 2010 due 11/15/2040, 5.125%	$3,087,880.00	$0.00	$103,360.00	$2,984,520.00
Total (226)		$3,948,318.00	$0.00	$279,860.00	$3,668,458.00

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Unamortized Loss and Gain on Reqcquired Debt (189,257) (Ref Page: 260)

	Designation of	Date Reacquired (b)	Principle of Debt	Net Gain or Loss (d)	Balance Beginning of	Balance End of Year (f)
Acct 189						
(189)			$0.00	$0.00	$0.00	$0.00
(189)	1985 Series J, due 07/01/1995	08/01/1990	$25,000,000.00	$787,340.00	$141,715.00	$110,214.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)	1976 Series A, due 9/1/2006	08/01/1993	$35,200,000.00	$439,383.00	$56,634.00	$34,722.00
(189)	1975 Series A, due 9/1/2000	10/01/1992	$31,000,000.00	$286,757.00	$76,469.00	$64,997.00
(189)	1987 Series A, due 08/01/1997	10/01/1992	$60,000,000.00	$2,574,187.00	$686,490.00	$583,506.00
(189)	1990 Series A, due 06/15/2015	06/01/2000	$25,000,000.00	$2,171,404.00	$1,323,303.00	$1,242,279.00
(189)	1990 Series A TC, due 11/01/2020	08/01/2000	$83,335,000.00	$4,298,037.00	$2,813,977.00	$2,670,277.00
(189)	1996 Series A JC, due 09/01/2026	03/01/2002	$22,500,000.00	$1,896,244.00	$1,213,033.00	$1,135,609.00
(189)	1996 Series A TC, due 09/01/2026	03/01/2002	$27,500,000.00	$1,601,630.00	$1,024,525.00	$959,125.00
(189)	1997 Series A JC, due 11/01/2027	03/01/2002	$35,000,000.00	$1,256,362.00	$825,635.00	$776,579.00
(189)	1997 Series A TC, due 11/01/2027	03/01/2002	$35,000,000.00	$1,251,639.00	$822,566.00	$773,702.00
(189)	1990 Series B TC, due 11/01/2020	10/01/2002	$41,665,000.00	$1,671,182.00	$1,214,034.00	$1,158,222.00
(189)	1995 Series A JC, due 04/15/2023	11/01/2005	$40,000,000.00	$1,397,647.00	$1,128,172.00	$1,081,324.00

Unamortized Loss and Gain on Reqcquired Debt (189,257) (Ref Page: 260)

	Designation of	Date Reacquired (b)	Principle of Debt	Net Gain or Loss (d)	Balance Beginning of	Balance End of Year (f)
(189)	1993 Series B JC, due 10/15/2020	11/01/2003	$26,000,000.00	$5,683,169.00	$4,328,947.00	$4,137,964.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)	1992 Series A JC due 09/01/2017	04/26/2007	$31,000,000.00	$130,784.00	$112,138.00	$107,136.00
(189)	1992 Series A TC, due 09/01/2017	04/26/2007	$60,000,000.00	$172,943.00	$148,287.00	$141,672.00
(189)	1993 Series A JC, due 08/15/2013	04/26/2007	$35,200,000.00	$74,067.00	$63,507.00	$60,674.00
(189)	2005 Series A JC, due 02/01/2035	03/24/2008	$40,000,000.00	$1,325,894.00	$1,194,450.00	$1,144,853.00
(189)	2000 Series A JC, due 05/01/2027	05/01/2008	$25,000,000.00	$692,833.00	$601,994.00	$806,386.00
(189)	2003 Series A JC, due 10/01/2033	07/08/2008	$128,000,000.00	$3,076,081.00	$2,782,207.00	$2,659,463.00
(189)	2007 Series A JC, due 06/01/2033	04/04/2008	$31,000,000.00	$915,910.00	$823,030.00	$786,315.00
(189)	2007 Series B JC, due 06/01/2033	04/04/2008	$35,200,000.00	$620,418.00	$553,537.00	$528,844.00
Total (189)			$872,600,000.00	$32,323,911.00	$21,934,650.00	$20,963,863.00
Acct 257						
(257)						
Total (257)			$0.00	$0.00		$0.00

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes (Ref Page: 261)

	Details (a)	Amount (b)
Net Income for the Year		$124,352,697.00
Reconciling Items for the Year		
Taxable Income Not Reported on Books		
	Environmental Cost Recovery	$5,039,496.00
	Contributions In Aid Of Construction	$3,600,250.00
Deductions Recorded on Books Not Deducted For Return		
	Federal Income Taxes - Utility Operation Income	$11,962,850.00
	Federal Income Taxes - Other Income and Deductions	($489,148.00)
	Provision for Deferred Income Taxes	$54,166,643.00
	MISO Exit Fees-Transmission	$1,030,463.00
	Capitalized Interest	$6,606,874.00
	Loss on Reacquired Debt, Net of Amortization	$970,787.00
	Workers' Compensation	$1,570,093.00
	Asset Retirement Obligations	$2,109,576.00
	Regulatory Expenses	$770,723.00
	Prepaid Insurance	$1,652,429.00
	Storm Damages	$6,737,872.00
	Other	$1,488,394.00
	Purchase Accounting Adjustment-FMV Leases	$27,885.00
Income Recorded on Books Not Included in Return		
	Amortization of Investment Tax Credit	$2,805,732.00
	Customer Advances for Construction	$1,215,871.00
	Purchased Gas Adjustment	$5,919,805.00
	Fuel Adjustment Clause KY	$407,000.00
	Mark to Market	$1,404,045.00
Deductions on Return Not Charged Against Book Income		
	Method Life Depreciation	$128,406,173.00

Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes (Ref Page: 261)

	Details (a)	Amount (b)
	Cost of Removal	$11,881,355.00
	Demand Side Management	$1,415,758.00
	Post Retirement Benefits	$6,168,959.00
	Summer Storm Damages	$8,052,125.00
	IRC 199 Manufacturing Deduction	$2,299,901.00
	Bad Debts Reserves	$509,141.00
	Contingent Liability	$756,814.00
	Current State Income Taxes	$1,627,412.00
	Other	$389,418.00
	Purchase Accounting Adjustment-FMV Leases	$300,212.00
Federal Tax Net Income		$48,038,163.00
Show Computation of Tax		
	Federal Tax Net Income	$48,038,163.00
	35% Rounded	$16,813,357.00
	Add: Adjustment of Prior Years' Taxes and Other	($5,339,655.00)
	Total:	$11,473,702.00

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Taxes Accrued, Prepaid and Charged During Year (Ref Page: 262)

	Kind of Instruction (a)	Bal Beg Yr Taxes Accr (b)	Bal Beg Yr Prepaid Taxes (c)	Taxes Chrg (d)
	Federal:	$0.00	$0.00	$0.00
	Income	($3,741,320.00)	$0.00	$14,303,728.00
	FICA	$590,647.00	$0.00	$6,396,768.00
		$0.00	$0.00	$0.00
	Kentucky & Other States:	$0.00	$0.00	$0.00
	Vehicle License	$0.00	$0.00	$87,826.00
	Income	$229,109.00	$0.00	$9,573,551.00
	Public Service Commission	$0.00	$966,581.00	$1,943,900.00
	Use (Kentucky)	$1,088,858.00	$0.00	$4,804,649.00
	Use (Indiana)	$0.00	$0.00	$29,808.00
		$0.00	$0.00	$0.00
	Federal & Kentucky:	$0.00	$0.00	$0.00
	Unemployment Insurance	$54,387.00	$0.00	$141,296.00
		$0.00	$0.00	$0.00
	Local:	$0.00	$0.00	$0.00
	Occupational	$0.00	$0.00	$0.00
	Federal, State & Local:	$0.00	$0.00	$0.00
	Miscellaneous	$0.00	$0.00	$35.00
		$0.00	$0.00	$0.00
	Kentucky & Indiana:	$0.00	$0.00	$0.00
	Property Taxes	$11,376,472.00	$0.00	$18,302,701.00
Total		$9,598,153.00	$966,581.00	$55,584,262.00

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Taxes Accrued, Prepaid and Charged During Year (Ref Page: 262) (Part Two)

	Kind of Instruction (a)	Taxes Paid (e)	Adj (f)	Bal Accr - 236 (g)	Bal Prepaid - 165 (h)
	Federal:	$0.00	$0.00	$0.00	$0.00
	Income	$10,562,408.00	$0.00	$0.00	$0.00
	FICA	$6,461,380.00	$0.00	$526,035.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Kentucky & Other States:	$0.00	$0.00	$0.00	$0.00
	Vehicle License	$87,826.00	$0.00	$0.00	$0.00
	Income	$9,802,660.00	$0.00	$0.00	$0.00
	Public Service Commission	$1,954,639.00	$0.00	$0.00	$977,320.00
	Use (Kentucky)	$5,221,713.00	$0.00	$671,794.00	$0.00
	Use (Indiana)	$29,808.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Federal & Kentucky:	$0.00	$0.00	$0.00	$0.00
	Unemployment Insurance	$142,353.00	$0.00	$53,329.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Local:	$0.00	$0.00	$0.00	$0.00
	Occupational	$0.00	$0.00	$0.00	$0.00
	Federal, State & Local:	$0.00	$0.00	$0.00	$0.00
	Miscellaneous	$35.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Kentucky & Indiana:	$0.00	$0.00	$0.00	$0.00
	Property Taxes	$17,645,481.00	$0.00	$12,033,692.00	$0.00
Total		$51,908,303.00	$0.00	$13,284,850.00	$977,320.00

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Taxes Accr, Prepd and Charged - Distribution of Taxes (Ref Page: 262)

	Kind of Instruction (a)	Electric (408.1, 409.1) (i)	Gas (408.1, 409.1) (j)	Other (408.1,409.1) (k)	Other Inc and Ded (l)
	Federal:	$0.00	$0.00	$0.00	$0.00
	Income	$27,439,818.00	($15,476,967.00)	$0.00	($489,148.00)
	FICA	$6,370,094.00	$1,440,098.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Kentucky & Other States:	$0.00	$0.00	$0.00	$0.00
	Vehicle License	$0.00	$0.00	$0.00	$0.00
	Income	$9,971,422.00	($1,705,889.00)	$0.00	($90,284.00)
	Public Service Commission	$1,426,854.00	$517,046.00	$0.00	$0.00
	Use (Kentucky)	$0.00	$0.00	$0.00	$0.00
	Use (Indiana)	$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Federal & Kenucky:	$0.00	$0.00	$0.00	$0.00
	Unemployment Insurance	$162,498.00	$35,645.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Local:	$0.00	$0.00	$0.00	$0.00
	Occupational	$37,061.00	$9,256.00	$0.00	$0.00
	Federal, State & Local:	$0.00	$0.00	$0.00	$0.00
	Miscellaneous	$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Kentucky & Indiana:	$0.00	$0.00	$0.00	$0.00
	Property Taxes	$13,613,677.00	$4,509,354.00	$0.00	$3,168.00
Total		$59,021,424.00	($10,671,457.00)	$0.00	($576,264.00)

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Taxes Accr, Prepd and Charged - Distribution of Taxes (Ref Page: 262) (Part Two)

	Kind of Instruction (a)	Ext Items (409.3) (m)	Other Opn Income (n)	Adj to Ret. Earnings (439)	Other (p)
	Federal:	$0.00	$0.00	$0.00	$0.00
	Income	$0.00	$0.00	$0.00	$2,830,026.00
	FICA	$0.00	$0.00	$0.00	($1,413,424.00)
		$0.00	$0.00	$0.00	$0.00
	Kentucky & Other States:	$0.00	$0.00	$0.00	$0.00
	Vehicle License	$0.00	$0.00	$0.00	$87,826.00
	Income	$0.00	$0.00	$0.00	$1,398,302.00
	Public Service Commission	$0.00	$0.00	$0.00	$0.00
	Use (Kentucky)	$0.00	$0.00	$0.00	$4,804,649.00
	Use (Indiana)	$0.00	$0.00	$0.00	$29,808.00
		$0.00	$0.00	$0.00	$0.00
	Federal & Kenucky:	$0.00	$0.00	$0.00	$0.00
	Unemployment Insurance	$0.00	$0.00	$0.00	($56,847.00)
		$0.00	$0.00	$0.00	$0.00
	Local:	$0.00	$0.00	$0.00	$0.00
	Occupational	$0.00	$0.00	$0.00	($46,317.00)
	Federal, State & Local:	$0.00	$0.00	$0.00	$0.00
	Miscellaneous	$0.00	$0.00	$0.00	$35.00
		$0.00	$0.00	$0.00	$0.00
	Kentucky & Indiana:	$0.00	$0.00	$0.00	$0.00
	Property Taxes	$0.00	$0.00	$0.00	$176,502.00
Total		$0.00	$0.00	$0.00	$7,810,560.00

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Miscellaneous Current and Accrued Liabilities (242) (Ref Page: 268)

	Item (a)	Balance End Yr (b)
	Vested Vacation Pay Accrued	$5,980,227.00
	No-Notice Gas Payable	$4,808,672.00
	Customer Overpayments	$4,191,986.00
	Home Energy Assistance	$511,591.00
	Retirement Income Liability	$436,164.00
	Unearned Revenue - Current	$390,305.00
	Miscellaneous	$216,356.00
TOTAL		$16,535,301.00

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Other Deferred Credits (253) (Ref Page: 269)

Description (a)	Balance Beg Yr (b)	Debits Acct (c)	Debit Amt (d)	Credits (e)	Balance End Yr (f)
Valuation of Coal Contracts (Nov-10 to Dec-15)	$9,214,861.00	182.3	$4,282,428.00	$0.00	$4,932,433.00
Brown CT Long-Term Service Agreement	$4,460,129.00	232/107	$722,458.00	$92,951.00	$3,830,622.00
Corporate Headquarters Lease (Nov-10 to Jul-15)	$766,828.00	182.3	$167,308.00	$0.00	$599,520.00
Prepaid Transmission System Fee: MCI Telecom	$631,668.00	454	$36,796.00	$0.00	$594,872.00
Deferred Compensation	$493,696.00	0	$0.00	$33,542.00	$527,238.00
CSX Transmission Line Construction	$0.00	107	$273,304.00	$368,000.00	$94,696.00
Unearned Revenue Pole Attachments	$45,764.00	0	$0.00	$0.00	$45,764.00
Clearing Accts Transferred from Other Def. Debits	$45,813.00	184	$30,385,875.00	$30,367,238.00	$27,176.00
TOTAL	$15,658,759.00		$35,868,169.00	$30,861,731.00	$10,652,321.00

Note:
Valuation of Coal Contracts (Nov-10 to Dec-15), Column f
The balance of $4,932,433 relates to the fair value measurement of $11,262,929 for the Louisville Gas and Electric 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.

Corporate Headquarters Lease (Nov-10 to Jul-15), Column f
The balance of $599,520 relates to the revaluation of $794,713 for Louisville Gas and Electric Company's rent commitment for the Corporte 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.

CSX Transmission Line Construction, Column f
In 2011, CSX Corporation requested Louisville Gas and Electric Company move transmission lines and related equipment on CSX property.

Accumulated Deferred Income Taxes - Other Property (282) (Ref Page: 274)

	Acct (a)	Balance Beg Yr (b)	Amt Acct 410.1 (c)	Amt Acct 411.1 (d)	Amt Acct 410.2 (e)	Amt Acct 411.2 (f)
Account 282						
Electric		$358,504,863.00	$108,250,773.00	$118,293,380.00	$0.00	$0.00
Gas		$64,465,864.00	$48,078,985.00	$19,035,813.00	$0.00	$0.00
Other (Define)						
Total		$422,970,727.00	$156,329,758.00	$137,329,193.00	$0.00	$0.00
Other (specify)						
TOTAL Acct 282		$422,970,727.00	$156,329,758.00	$137,329,193.00	$0.00	$0.00
Classification of Total						
Federal Income Tax		$362,343,439.00	$128,518,249.00	$106,311,257.00	$0.00	$0.00
State Income Tax		$60,627,288.00	$27,811,509.00	$31,017,936.00	$0.00	$0.00
Local Income tax						

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Accumulated Deferred Income Taxes - Other Property (282) (Ref Page: 274) (Part Two)

Acct (a)	Debit Adj Acct (g)	Debit Adj Amt (h)	Credit Adj. Acct (i)	Credit Adj. Amt (j)	Balance End Yr
Account 282					
Electric	254	$38,283,384.00	254/190	$47,798,780.00	$357,977,652.00
Gas	254	$11,969,418.00	254	$11,900,463.00	$93,440,081.00
Other (Define)					
Total		$50,252,802.00		$59,699,243.00	$451,417,733.00
Other (specify)					
TOTAL Acct 282		$50,252,802.00		$59,699,243.00	$451,417,733.00
Classification of Total					
Federal Income Tax		$33,368,853.00		$40,703,628.00	$391,885,206.00
State Income Tax		$16,883,949.00		$18,995,615.00	$59,532,527.00
Local Income tax					

Accumulated Deferred Income Taxes - Other (283) (Ref Page: 276)

	Acct (a)	Balance Beg Yr (b)	Amt Acct 410.1 (c)	Amt Acct 411.1 (d)	Amt Acct 410.2 (e)	Amt Acct 411.2 (f)
Account 283						
Electric		$120,270,719.00	$24,494,690.00	$42,267,377.00	$0.00	$0.00
Gas		($2,490,387.00)	$8,595,333.00	$5,019,514.00	$0.00	$0.00
Other						
Total		$117,780,332.00	$33,090,023.00	$47,286,891.00	$0.00	$0.00
Other (Specify)						
	Swap Termination	$3,577,127.00	$0.00	$0.00	$2,180,471.00	$2,180,471.00
TOTAL (Acct 283)		$121,357,459.00	$33,090,023.00	$47,286,891.00	$2,180,471.00	$2,180,471.00
Classification of Total						
Federal Income Tax		$102,639,085.00	$28,590,216.00	$40,597,336.00	$1,876,925.00	$1,876,925.00
State Income Tax		$18,718,374.00	$4,499,807.00	$6,689,555.00	$303,546.00	$303,546.00
Local Income tax						

Accumulated Deferred Income Taxes - Other (283) (Ref Page: 276) (Part Two)

	Acct (a)	Debit Adj Acct (g)	Debit Adj Amt (h)	Credit Adj. Acct (i)	Credit Adj. Amt (j)	Balance End Yr
Account 283						
Electric			$0.00	182/283	$9,307,149.00	$111,805,181.00
Gas			$0.00		$0.00	$1,085,432.00
Other						
Total			$0.00		$9,307,149.00	$112,890,613.00
Other (Specify)						
	Swap Termination	283	$3,577,127.00		$0.00	$0.00
TOTAL (Acct 283)			$3,577,127.00		$9,307,149.00	$112,890,613.00
Classification of Total						
Federal Income Tax			$3,025,385.00		$7,871,599.00	$95,478,179.00
State Income Tax			$551,742.00		$1,435,550.00	$17,412,434.00
Local Income tax						

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Other Regualatory Liabilities (Acct 254) (Ref Page: 278)

	Description and Purpose	Bal Beg Yr (b)	Debit Acct Credited (c)	Debits Amount (d)	Credits (e)	Balance End Yr (f)
	ASC 740 - Income Taxes	$33,521,842.00	190/282	$1,890,695.00	$14,500,596.00	$46,131,743.00
	Gas Supply Clause	$9,053,548.00	182.3/495/803	$8,064,392.00	$4,050,828.00	$5,039,984.00
	Environmental Cost Recovery	$0.00	440-445	$543,222.00	$862,409.00	$319,187.00
	Asset Retirement Obligation - Electric	$787,905.00	108	$672,302.00	$73,006.00	$188,609.00
	Asset Retirement Obligation - Gas	$2,387,519.00	108	$258,005.00	$19,894.00	$2,149,408.00
	DSM Cost Recovery	$5,099,134.00	440-489	$6,165,946.00	$4,750,187.00	$3,683,375.00
	MISO Exit Fee Refund	$346,129.00	0	$0.00	$280,629.00	$626,758.00
	Purchased Gas Adjustment	$230,271.00	495/803	$325,178.00	$573,439.00	$478,532.00
	Coal Contracts (Nov-10 to Dec-16)	$117,659,961.00	186	$39,340,574.00	$0.00	$78,319,387.00
	OVEC Power Purchase Contract (Nov-10 to Mar-26)	$85,809,209.00	186	$5,472,941.00	$0.00	$80,336,268.00
	Emission Allowances (Nov-10 to Dec-40)	$7,433,400.00	186	$5,419,213.00	$0.00	$2,014,187.00
Total		$262,328,918.00		$68,152,468.00	$25,110,988.00	$219,287,438.00

Note:
ASC 740 Income Taxes, Column f
The regulatory liabilities represent the future revenue impact from the reversal of deferred income taxes required for unamortized investment tax credits and deferred taxes provided at rates in excess of currently enacted rates.

See additional footnotes in hard copy Annual Gas Report.

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Other Regulatory Liabilities (Acct 254) (Ref Page: 278) - NOTES

Coal Contracts (Nov-10 to Dec-16), Column f:
The balance relates to the regulatory offset for the fair value measurement of LG&E's coal contracts recognized due to the purchase of LG&E 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		123,813,249
2011 Amortization of Purchase Accounting Adjustment		(39,340,574)
2010 Amortization of Purchase Accounting Adjustment		(6,153,288)
Total for Coal Contracts (Nov-10 to Dec-16)	$	78,319,387

OVEC Power Purchase Contract (Nov-10 to Mar-26), Column f:
The balance relates to the regulatory offset for the fair value measurement of the power purchase contract between LG&E and Ohio Valley Electric Corporation recognized due to the purchase of LG&E 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		86,856,705
2011 Amortization of Purchase Accounting Adjustment		(5,472,941)
2010 Amortization of Purchase Accounting Adjustment		(1,047,496)
Total for OVEC Power Purchase Contract (Nov-10 to Mar-26)	$	80,336,268

Emission Allowances (Nov-10 to Dec-40), Column f:
The balance relates to the regulatory offset for the fair value measurement of LG&E's emission allowances recognized due to the purchase of LG&E 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		8,359,713
2011 Amortization of Purchase Accounting Adjustment		(5,419,213)
2010 Amortization of Purchase Accounting Adjustment		(926,313)
Total for Emission Allowances (Nov-10 to Dec-40)	$	2,014,187

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Gas Operating Revenues (Ref Page: 301)

	Rev for Transistion Current	Rev for Transistion Prev Yr	GRI and ACA Current Yr (d)	GRI and ACA Prev Yr (e)	other Current Yr (f)
Sales (480-484)	$294,536,126.00	$292,321,326.00	$0.00	$0.00	$0.00
Intracompany Transfers (485)					
Forfeited Discounts (487)	$2,815,529.00	$3,109,203.00	$0.00	$0.00	$0.00
Miscellaneous Service Revenues (488)	$91,030.00	$93,977.00	$0.00	$0.00	$0.00
Revenues from Transportaion of Gas of Others Through Gathering Facilities (489.1)					
Revenues from Transportaion of Gas of Others Through Transmission Facilities (489.2)	$1,287,774.00	$1,308,782.00	$0.00	$0.00	$0.00
Revenues from Transportaion of Gas of Others Through Distribution Facilities (489.3)	$5,628,038.00	$5,803,421.00	$0.00	$0.00	$0.00
Sales of Prod. Ext. from Natural Gas (490)					
Revenues from Natural Gas Proc. by Others (491)					
Incidental gasoline and Oil Sales (492)					
Rent from Gas Property (493)	$206,285.00	$302,137.00	$0.00	$0.00	$0.00
Interdepartmental Rents (494)					
Other Gas Revenues (495)	$9,640.00	$8,510.00	$0.00	$0.00	$0.00
Subtotal	$304,574,422.00	$302,947,356.00	$0.00	$0.00	$0.00
(Less) Provision for Rate Refunds (496)					
Total	$304,574,422.00	$302,947,356.00	$0.00	$0.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Gas Operating Revenues (Ref Page: 301) (Part Two)

	Rev for Transistion	Other Prev Yr (g)	Total Current Yr (h)	Total Prev Yr (i)	MCF Current Yr (h)	MCF Prev Yr (i)
Sales (480-484)	$294,536,126.00	$0.00	$294,536,126.00	$292,321,326.00	31,130,203	33,485,975
Intracompany Transfers (485)						
Forfeited Discounts (487)	$2,815,529.00	$0.00	$2,815,529.00	$3,109,203.00	0	0
Miscellaneous Service Revenues (488)	$91,030.00	$0.00	$91,030.00	$93,977.00	0	0
Revenues from Transportaion of Gas of Others Through Gathering Facilities (489.1)						
Revenues from Transportaion of Gas of Others Through Transmission Facilities (489.2)	$1,287,774.00	$0.00	$1,287,774.00	$1,308,782.00	336,775	165,317
Revenues from Transportaion of Gas of Others Through Distribution Facilities (489.3)	$5,628,038.00	$0.00	$5,628,038.00	$5,803,421.00	11,242,723	11,078,599
Sales of Prod. Ext. from Natural Gas (490)						
Revenues from Natural Gas Proc. by Others (491)						
Incidental gasoline and Oil Sales (492)						
Rent from Gas Property (493)	$206,285.00	$0.00	$206,285.00	$302,137.00	0	0
Interdepartmental Rents (494)						
Other Gas Revenues (495)	$9,640.00	$0.00	$9,640.00	$8,510.00	0	0
Subtotal	$304,574,422.00	$0.00	$304,574,422.00	$302,947,356.00	42,709,701	44,729,891

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Gas Operating Revenues (Ref Page: 301) (Part Two)

	Rev for Transistion	Other Prev Yr (g)	Total Current Yr (h)	Total Prev Yr (i)	MCF Current Yr (h)	MCF Prev Yr (i)
(Less) Provision for Rate Refunds (496)						
Total	$304,574,422.00	$0.00	$304,574,422.00	$302,947,356.00	42,709,701	44,729,891

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Rev From Transportation of Gas through Transmission Facilities (489.2) (Ref Page: 304)

Rate Schedule and Zone	Rev for Transition Costs	Rev for Transition Costs	Rev for GRI and ACA	Rev for GRI and ACA	Other Rev Current (f)
RATE FT/PADDY'S RUN	$1,287,774.00	$1,308,782.00	$0.00	$0.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Rev From Transportation of Gas through Transmission Facilities (489.2) (Ref Page: 304) (Part Two)

Rate Schedule and Zone	Other Rev Previous (g)	Total Operating Rev	Total Operating Rev	MCF Current (j)	MCF Previous (k)
RATE FT/PADDY'S RUN	$0.00	$1,287,774.00	$1,308,782.00	336,775	165,317

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Rev From Stroring Gas of Others (489.4) (Ref Page: 306)

Rate Schedule and Zone	Rev for Transition Costs	Rev for Transition Costs	Rev for GRI and ACA	Rev for GRI and ACA	Other Rev Current (f)

Rev From Stroring Gas of Others (489.4) (Ref Page: 306) (Part Two)

Rate Schedule and Zone	Other Rev Previous (g)	Total Operating Rev	Total Operating Rev	MCF Current (j)	MCF Previous (k)

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Other Gas Revenues (495) (Ref Page: 308)

Description of Transaction	Revenues in Dollars
Miscellaneous - All Minor Items	$9,640.00
	$9,640.00

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Gas Operation and Maintenance - 1. Production (Ref Page: 317)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
1. PRODUCTION EXPENSES		
A. Manufactured Gas Production		
Manufactured Gas Production		
B. Natural Gas Production		
B1. Natural Gas Produciton and Gathering		
Operation		
Operation Supervision and Engineering (750)		
Production Maps and Records (751)		
Gas Well Expenses (752)		
Field Lines Expenses (753)		
Field compressor Station Expenses (754)		
Field Compressor Station Fuel and Power (755)		
Field Measuring and Regulating Station Expenses (756)		
Purification Expenses (757)		
Gas Well Royalties (758)		
Other Expenses (759)		
Rents (760)		
18. Total Operation		
Maintenance		
Maintenance Supervision and Engineering (761)		
Maintenance of Structures and Improvements (762)		
Maintenance of Producing Gas Wells (763)		
Maintenance of Field Lines (764)		
Maintenance of Field Compressor Station Equipment (765)		
Maintenance of Field Measuring and Regulating Station Equipment (766)		
Maintenance of Purification Equipment (767)		

Gas Operation and Maintenance - 1. Production (Ref Page: 317)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Maintenance of Drilling and Cleaning Equipment (768)		
Maintenance of Other Equipment (769)		
29. Total Maintenance		
Total Natural Gas Production and Gathering (Lines 18,29(		
B2. Products Extraction		
Operation		
Operation Supervision and Engineering (770)		
Operation Labor (771)		
Gas Shrinkage (772)		
Fuel (773)		
Power (774)		
Materials (775)		
Operation Supplies and Expenses (776)		
Gas Processed by Others (777)		
Royalties on Products Extracted (778)		
Marketing Expenses (779)		
Products Purchased for Resale (780)		
Variation in Products Inventory (781)		
(Less) Extracted Products Used by the Utility - Credit (782)		
Rents (783)		
47. Total Operation		
Maintenance		
Maintenance Supervision and Engineering (784)		
Maintenance of Structures and Improvements (785)		
Maintenance of Extraction and Refining Equipment (786)		
Maintenance of Pipe Lines (787)		
Maintenance of Extracted Products Storage Equipment (788)		

Gas Operation and Maintenance - 1. Production (Ref Page: 317)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Maintenance of Compressor Equipment (789)		
Maintenance of Gas Measuring and Regulating Equipment (790)		
Maintenance of Other Equipment (791)		
57. Total Maintenance		
58. Total Products Extraction (Lines 47 and 57)		
C. Exploration and Development		
Operation		
Delay Rentals (795)		
Nonproductive Well Drilling (796)		
Abandoned Leases (797)		
Other Exporation (798)		
65. Total Exploration and Development		
D. Other Gas Supply Expenses		
Operation		
Natural Gas Well Head Purchases (800)		
Natural Gas Well Head Purchases, Intracompany Transfers (800.1)		
Natural Gas Field Line Purchases (801)		
Natural Gas Gasoline Plant Outlet Purchases (802)		
Natural Gas Transmission Line Purchases (803)	$158,593,798.00	$174,326,298.00
Natural Gas City Gate Purchases (804)		
Liquified Natural Gas Purchases (804.1)		
Other Gas Purchases (805)		
(Less) Purchases Gas Cost Adjustments (805.1)		
77. Total Purchased Gas	$158,593,798.00	$174,326,298.00
78. Exchange Gas (806)	($1,823,878.00)	$695,699.00
Purchased Gas Expense		

Gas Operation and Maintenance - 1. Production (Ref Page: 317)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Well Expense - Purchased Gas (807.1)		
Operation of Purchased Gas Measuring Stations (807.2)		
Maintenance of PUrchased Gas Measuring Stations (807.3)		
Purchased Gas Calculations Expenses (807.4)	$33,797.00	$32,970.00
Other Purchased Gas Expenses (807.5)	$732,148.00	$703,703.00
85. Total Purchased Gas Expenses	$765,945.00	$736,673.00
Gas Withdrawn from Storage - Debit (808.1)	$59,838,142.00	$56,983,855.00
(Less) Gas Delivered to Storage (Credit) (808.2)	$55,399,465.00	$63,075,768.00
Withdrawals of Liquefied natural Gas for Processing - Debit (809.1)		
(Less) Delieveries of Natural Gas for Processing- Credit (809.2)		
Gas used in Utility Operation - Credit		
91. Gas Used for Compressor Station Fuel - Credit (810)	($630,080.00)	($513,870.00)
92..Gas Used for Products Extraction - Credit (811)		
93..Gas Used for Other Utility Operations - Credit (812)	($108,837.00)	($149,278.00)
94. Total Gas Used in Utility Operations - Credit (91-93)	($738,917.00)	($663,148.00)
95. Other Gas Supply Expenses (813)	$1.00	$0.00
97. Total Other Gas Supply Exp (77,78,85,86-89,94,95)	$161,235,626.00	$169,003,609.00
Total Production Expenses (3,30,58,65,96)	$161,235,626.00	$169,003,609.00

Gas Operation and Maintenance - 2. Natural Gas Storage (Ref Page: 320)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
A. Underground Storage Expenses		
Operation		
Operation Supervision and Engineering (814)	$505,548.00	$509,942.00
Maps and Records (815)		
Wells Expenses (816)	$293,305.00	$170,899.00
Lines Expenses (817)	$587,845.00	$658,994.00
Compressor Station Expenses (818)	$1,514,578.00	$1,587,092.00
Compressor Station Fuel and Power (819)	$629,062.00	$488,228.00
Measuring and Regulating Station Expenses (820)		
Purification Expenses (821)	$1,342,930.00	$1,360,704.00
Exploration and Development (822)		
Gas Losses (823)	$2,229,899.00	$2,319,049.00
Other Expenses (824)	$13,217.00	$10,128.00
Storage well Royalties (825)	$47,717.00	$40,974.00
Rents (826)	$39,891.00	$46,696.00
114. Total Operation	$7,203,992.00	$7,192,706.00
Maintenance		
Maintenance Supervision and Engineering (830)	$370,519.00	$366,028.00
Maintenance of Structures and Improvements (831)		
Maintenance of Reservoirs and Wells (832)	$778,256.00	$547,233.00
Maintenance of Lines (833)	$159,586.00	$149,717.00
Maintenance of Compressor Station Equipment (834)	$796,313.00	$940,068.00
Maintenance of Measuring and Regulating Station Equipment (835)	$31,455.00	$25,473.00
Maintenance of Purification Equipmetn (836)	$873,221.00	$614,741.00

Gas Operation and Maintenance - 2. Natural Gas Storage (Ref Page: 320)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Maintenance of Other Equipment (837)	$55,177.00	$33,962.00
124. Total Maintenance	$3,064,527.00	$2,677,222.00
Total Underground Storage (Lines 114 and 124)	$10,268,519.00	$9,869,928.00
B. Other Storage Expenses		
Operation		
Operation Supervision and Engineering (840)		
Operation Labor and Expenses (841)		
Rents (842)		
Fuel (842.1)		
Power (842.2)		
Gas Losses (842.3)		
134. Total Operation		
Maintenance		
Maintenance Supervision and Engineering (843.1)		
Maintenance of Structures and Improvements (843.2)		
Maintenance of Gas Holders (843.3)		
Maintenance of Purification Equipment (843.4)		
Maintenance of Liquefaction Equipment (843.5)		
Maintenance of Vaporizing Equipment (843.6)		
Maintenance of Compressor Equipment (843.7)		
Maintenance of Measuring and Regulating Equipment (843.8)		
Maintenance of Other Equipment (843.9)		
145. TOTAL Maintenance		
Total Other Storage Expenses (Lines 134 and 145)		
C. Liquefied Natural Gas Terminaling and Processing Expenses		
Operation		
Operation Supervision and Engineering (844.1)		

Gas Operation and Maintenance - 2. Natural Gas Storage (Ref Page: 320)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
LNG Processing Terminal Labor and Expenses (844.2)		
Liquefaction Processing Labor and Expenses (844.3)		
Liquefaction Transportaion Labor and Expenses (844.4)		
Measuring and Regulating Labor and Expenses (844.5)		
Compressor Station Labor and Expenses (544.6)		
Communication System Expenses (844.7)		
System Control and Load Dispatching (844.8)		
Fuel (845.1)		
Power (845.2)		
Rents (845.3)		
Demurrage Charges (845.4)		
(Less) Wharfage Receipts - Credit (845.5)		
Processing Liquefied or Vaporized Gas by Others (845.6)		
Gas Losses (846.1)		
Other Expenses (846.2)		
Total Operation		
Maintenance		
Maintenance Supervision and Engineering (847.1)		
Maintenance of Structures and Improvements (847.2)		
Maintenance of LNG Processing Terminal equipment (847.3)		
Maintenance of LNG Transportation Equipment (847.4)		
Maintenance of Measuring and Regulating Equipment (847.5)		
Maintenance of Compressor Station Equipment (847.6)		
Maintenance of Communication Equipment (847.7)		
Maintenance of Other Equipment (847.8)		
175. Total Maintenance		

Gas Operation and Maintenance - 2. Natural Gas Storage (Ref Page: 320)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
176. Total Liquiefied Nat Gas Terminaling and Proc Exp (Lines 165 and 175)		
177. Total Natural Gas Storage (Lines 125,146 and 176)	$10,268,519.00	$9,869,928.00

Gas Operation and Maintenance - 3 through 8 (Ref Page: 323)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
3. TRANSMISSION EXPENSES		
Operation		
Operation Supervision and Engineering (850)	$8,786.00	$912.00
System Control and Load Dispatching (851)	$294,448.00	$289,010.00
Communication System Expenses (852)		
Compressor Station labor and Expenses (853)		
Gas for Compressor Station Fuel (854)		
Other Fuel and Power for Compressor Stations (855)		
Mains Expenses (856)	$336,240.00	$545,357.00
Measuring and Regulating Stations Expenses (857)		
Transmission and Compression of Gas by Others (858)		
Other Expenses (859)		
Rents (860)	$6,220.00	$6,196.00
191. Total Operation	$645,694.00	$841,475.00
Maintenance		
Maintenance Supervision and Engineering (861)		
Maintenance of Structures and Improvements (862)		
Maintenance of Mains (863)	$1,226,762.00	$846,473.00
Maintenance of Compressor Station Equipment (864)		
Maintenance of Measuring and Regulating Station Equipment (865)		
Maintenance of Communication Equipment (866)		
Maintenance of Other Equipment (867)		
200. Total Maintenance	$1,226,762.00	$846,473.00
201. Total Transmission Expenses (Total 191 and 200)	$1,872,456.00	$1,687,948.00
4. DISTRIBUTION EXPENSES		
Operation		

Gas Operation and Maintenance - 3 through 8 (Ref Page: 323)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Operation Supervision and Engineering (870)		
Distribution Load Dispatching (871)	$457,184.00	$417,448.00
Compressor Station Labor and Expenses (872)		
Compressor Station Fuel and Power (873)		
Mains and Services Expenses (874)	$3,021,171.00	$2,768,903.00
Measuring and Regulating station Expenses - General (875)	$729,918.00	$630,964.00
Measuring and Regulating Station Expenses - Industrial (876)	$289,493.00	$357,353.00
Measuring and Regulating Station Expenses - City Gas Check Station (877)	$127,275.00	$136,866.00
Meter and House Regulator Expenses (878)	$598,216.00	$77,800.00
Customer Installations Expenses (879)	$499,238.00	$450,571.00
Other Expenses (880)	$3,260,340.00	$3,209,410.00
Rents (881)	$10,529.00	$9,946.00
216. Total Operation	$8,993,364.00	$8,059,261.00
Maintenance		
Maintenance Supervision and Engineering (885)		
Maintenance of Structures and Improvements (886)	$577,465.00	$573,858.00
Maintenance of Mains (887)	$9,569,767.00	$8,352,791.00
Maintenance of Compressor Station Equipment (888)		
Maintenance of Measuring and Regulating Station Equipment - General (889)	$97,433.00	$72,962.00
Maintenance of Measuring and Regulating Station Equipment - Industrial (890)	$202,188.00	$177,911.00
Maintenance of Measuring and Regulating Station Equipment - City Gate Check Station (891)	$333,586.00	$291,975.00
Maintenance of Services (892)	$1,031,631.00	$1,034,740.00
Maintenance of Meters and House Regulators (893)		
Maintenance of Other Equipment (894)	$413,000.00	$381,274.00

Gas Operation and Maintenance - 3 through 8 (Ref Page: 323)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
228. Total Maintenance	$12,225,070.00	$10,885,511.00
229. Total Distribution Expenses (Lines 216 and 228)	$21,218,434.00	$18,944,772.00
5. CUSTOMER ACCOUNTS EXPENSES		
Operation		
Supervision (901)	$815,094.00	$773,820.00
Meter Reading Expenses (902)	$1,756,317.00	$1,659,704.00
Customer Records and Collections Expenses (903)	$4,233,792.00	$4,391,043.00
Uncollectible Accounts (904)	$1,025,501.00	$1,445,163.00
Miscellaneous Customer Accounst Expenses (905)	$323,653.00	$264,965.00
237. Total Customer Accounts Expenses	$8,154,357.00	$8,534,695.00
6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
Operation		
Supervision (907)	$57,339.00	$73,215.00
Customer Assistance Expenses (908)	$2,312,600.00	$3,577,035.00
Informational and Instructional Expenses (909)	$14,770.00	$23,400.00
Miscellaneous Customer Service and Informational Expenses (910)	$90,110.00	$122,967.00
244. Total Customer Service and Informational Expenses	$2,474,819.00	$3,796,617.00
7. SALES EXPENSES		
Operation		
Supervision (911)		
Demonstrating and Selling Expenses (912)		
Advertising Expenses (913)	$8,365.00	$13,310.00
Miscellaneous Sales Expenses (916)		
251. TOTAL Sales Expenses	$8,365.00	$13,310.00
8. ADMINISTRATIVE AND GENERAL EXPENSES		
Operation		

Gas Operation and Maintenance - 3 through 8 (Ref Page: 323)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Administrative and General Salaries (920)	$3,864,477.00	$3,568,388.00
Office Supplies and Expenses (921)	$1,220,747.00	$1,262,089.00
(Less) Administrative Expenses Transferred - Credit (922)	$364,791.00	$294,189.00
Outside Services Employed (923)	$1,188,739.00	$908,287.00
Property Insurance (924)	$107,399.00	$172,800.00
Injuries and Damanges (925)	$750,642.00	$259,966.00
Employee Pensions and benefits (926)	$9,559,609.00	$9,054,206.00
Franchise Requirements (927)	$561,552.00	$551,224.00
Regulatory Commission Expenses (928)	$243,135.00	$149,719.00
(Less) Duplicate Charges - Credit (929)	$590,614.00	$569,919.00
General Advertising Expenses (930.1)	$195,410.00	$117,243.00
Miscellaneous General Expenses (930.2)	$118,822.00	$331,363.00
Rents (931)	$396,612.00	$364,959.00
267. Total Operation	$17,251,739.00	$15,876,136.00
Maintenance		
269. Maintenance of General Plant (935)	$3,607,622.00	$3,133,873.00
270. Total Administrative and General (Total 267 and 269)	$20,859,361.00	$19,010,009.00
Total Gas O and M Expenses (Total Lines 97,177,201,229,237,244,251 and 270)	$226,091,937.00	$230,860,888.00

Note:
The balance in Rents (931) was adjusted due to the purchase of LG&E 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:

Rents (931) Without Purchase Accounting	$ 391,314
Purchase Accounting Adjustment	5,298

Total for Rents (931)	$ 396,612

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Exchange and Imbalance Transactions (Ref Page: 328)

	Zone/Rate Schedule	Gas Received Amount (b)	Gas Received MCF (c)	Gas Delivered Amount (d)	Gas Delivered MCF (e)
Total					

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22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Gas Used in Utility Operations (Ref Page: 331)

Purpose (a)	Acct Charged (b)	Natural Gas Used MCF (c)	Natural Gas Amount of Credit (d)	Manufactured Gas MCF (e)	Manufactured Gas Amount of Credit (f)
Gas Used for Compressor Station Fuel - Credit (810)	819	128,781	$630,080.00	0	$0.00
Gas Used For Products Extration - Credit (811)					
Gas Shrinkage and Other Usage in Respondent`s Own Processing					
Gas Shrinkage, etc. for Respondent`s Gas Processed by Others					
Gas Used for Other Utility Operations - Credit (812)					
(Report seperately each principal use. Group minor uses.)					
City Gate Station	877	8,531	$41,888.00	0	$0.00
Gas Used in Electric Generation	547	831	$4,728.00	0	$0.00
Various	Various	12,614	$62,221.00	0	$0.00
Total		150,757	$738,917.00	0	$0.00

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22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Other Gas Supply Expenses (813) (Ref Page: 334)

Description (a)	Amount (b)
Other Gas Supply Expense	$1.00
Total	$1.00

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Miscellaneous General Expenses (Acct 930.2) (Ref Page: 335)

	Description	Amount
Industry association dues		$711.00
Experimental and general research expenses.		
a. Gas Research Institute (GRI)		$0.00
b. Other		$0.00
Publishing and distributing information and reports to stockholders, trustee, registrar and transfer agent fees and expenses and other expenses		$0.00
Other		
	Market Research	$37,780.00
	IBEW Non-Billable Charges	$23,069.00
	Swap Termination Amortization	$52,677.00
	Miscellaneous (2 items)	$4,585.00
		$0.00
		$0.00
		$0.00
		$0.00
		$0.00
		$0.00
Total		$118,822.00

Note:
Per the Form 2 instructions, for other expenses, show the (a) purpose, (b) recipient and (c) amount of such items. List separately amounts of $250,000 or more however, amounts less than $250,000 may be grouped if the number of items of so grouped is shown.

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Depreciation, Depletion and Amortization of Gas Plant (403,403.1,404.1,404.2,404.3,405) (Ref Page: 336)

	Depreciation 403 (b)	Depreciation Exp	404.1 (d)	404.2 (e)	404.3 (f)	405 (g)	Total (h)
Intangible Plant							
Production Plant, manufactured gas							
Production and gathering plant, natural gas							
Products extraction plant							
Underground gas storage plant	$1,207,700.00	$613,491.00	$0.00	$0.00	$0.00	$0.00	$1,821,190.00
Other storage plant							
Base load LNG terminaling and processing plant							
Transmission plant	$67,028.00	$35,271.00	$0.00	$0.00	$0.00	$0.00	$102,299.00
Distribution plant	$14,716,687.00	$374,096.00	$0.00	$0.00	$0.00	$0.00	$15,090,783.00
General Plant	$252,937.00	$0.00	$0.00	$0.00	$0.00	$0.00	$252,937.00
Common plant - gas	$3,808,588.00	$598.00	$0.00	$0.00	$2,358,705.00	$0.00	$6,167,891.00
Other							
Total	$20,052,940.00	$1,023,455.00	$0.00	$0.00	$2,358,705.00	$0.00	$23,435,100.00

Depreciation, Depletion and Amortization of Gas Plant (cont) (Ref Page: 338)

	Functional Classification (a)	Plant Bases (thousands) (b)	Applied Depr or Amort Rates (c)
Production and Gathering Plant			
Offshore			
		0	0
Onshore			
		0	0
	Underground Storage Plant	81,062	2
Underground Gas Storage Plant			
Transmission Plant			
Offshore			
		0	0
Onshore			
		23,001	2
General Plant			
	General Plant	7,020	4
	Distribution Plant	611,758	3

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Particulars Concerning Cetrain Income Deductions and Interest Charges Accounts (Ref Page: 340)

Item (a)	Amount (b)
Account 426.1 - Donations	$0.00
Various	$1,859,300.00
Total Account 426.1	$1,859,300.00
Account 426.3 - Penalties	$192.00
Total Account 426.3	$192.00
Account 426.4 -Civic, Political & Related Activity	$0.00
Related Activities	$920,561.00
Total Account 426.4	$920,561.00
Account 426.5 - Other Deductions	$0.00
Interest Rate Swap Mark-to-Market	($1,541,953.00)
Various	$887,458.00
Total Account 426.5	($654,495.00)
Account 430-Interest on Debt to Associated Company	$0.00
LG&E and KU Energy LLC	$7,734.00
Kentucky Utilities Company	$1,929.00
Other	$0.00
Total Account 430	$9,663.00
Account 431 - Other Interest Expense	$0.00
Customer Deposits - 6% Interest Rate	$1,383,635.00
Interest on Tax Deficiencies	$14,000.00
DSM Cost Recovery	$15,098.00
Financial Liabilities	$1,116,089.00
Other	$0.00
Total Account 431	$2,528,822.00

Particulars Concerning Cetrain Income Deductions and Interest Charges Accounts (Ref Page: 340) - NOTES

Note:
Account 426.5 - Other Deductions:
Mark-to-market gain due to favorable pricing on forward transactions.

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Regulatory Commission Expenses (928) (Ref Page: 350)

Description (a)	Assessed by Reg Commission (b)	Expenses of the Utility (c)	Total Expenses (d)	Deferred in 182.3 Beg of Yr (e)	Expenses Incurred Charged to Department
Federal Energy Regulatory Commission	$0.00	$0.00	$0.00	$0.00	
Annual Charge	$471,098.00	$0.00	$471,098.00	$0.00	Electric
Administrative Charge, Project #289	$186,047.00	$0.00	$186,047.00	$0.00	Electric
Kentucky Public Service Commission	$0.00	$0.00	$0.00	$0.00	
2008 Rate Case - Electric (Mar-09 to Feb-12)	$0.00	$247,757.00	$247,757.00	$289,049.00	Electric
2008 Rate Case - Gas (Mar-09 to Feb-12)	$0.00	$82,993.00	$82,993.00	$96,825.00	Gas
2009 Rate Case - Electric (Aug-10 to Jul-13)	$0.00	$279,832.00	$279,832.00	$722,898.00	Electric
2009 Rate Case - Gas (Aug-10 to Jul-13)	$0.00	$160,142.00	$160,142.00	$413,700.00	Gas
	$657,145.00	$770,724.00	$1,427,869.00	$1,522,472.00	

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Regulatory Commission Expenses (928) (Ref Page: 350) (Part Two)

Description (a)	Expenses Incurred Charged to Acct (g)	Expenses Incurred Charged to Amount	Expenses Incurred Deferred to 182.3 (i)	Amortized Contra Acct (j)	Amortized Amt (k)	Deferred in 182.3 End of Yr (l)
Federal Energy Regulatory Commission		$0.00	$0.00		$0.00	$0.00
Annual Charge	928	$471,098.00	$0.00		$0.00	$0.00
Administrative Charge, Project #289	928	$186,047.00	$0.00		$0.00	$0.00
Kentucky Public Service Commission		$0.00	$0.00		$0.00	$0.00
2008 Rate Case - Electric (Mar-09 to Feb-12)	928	$247,757.00	$0.00	928	$247,757.00	$41,293.00
2008 Rate Case - Gas (Mar-09 to Feb-12)	928	$82,993.00	$0.00	928	$82,993.00	$13,832.00
2009 Rate Case - Electric (Aug-10 to Jul-13)	928	$279,832.00	$0.00	928	$279,832.00	$443,066.00
2009 Rate Case - Gas (Aug-10 to Jul-13)	928	$160,142.00	$0.00	928	$160,142.00	$253,558.00
		$1,427,869.00	$0.00		$770,724.00	$751,749.00

Distribution of Salaries and Wages - Electric (Ref Page: 355)

Specify	Direct Payroll (b)	Alloc Clearing Accts (c)	Total (d)
Electric			
Operation			
3. Production	$21,545,763.00	$4,813,643.00	$26,359,406.00
4. Transmission	$2,696,671.00	$741,664.00	$3,438,335.00
5. Distribution	$8,011,827.00	$1,190,326.00	$9,202,153.00
6. Customer Accounts	$3,440,063.00	$934,022.00	$4,374,085.00
7. Customer Service and Informational	$670,472.00	$168,930.00	$839,402.00
8. Sales	$0.00	$0.00	$0.00
9. Administrative and General	$12,709,457.00	$6,029,641.00	$18,739,098.00
10. Total Operation	$49,074,253.00	$13,878,226.00	$62,952,479.00
Maintenance			
12. Production	$11,221,975.00	$2,508,106.00	$13,730,081.00
13. Transmission	$302,086.00	$71,068.00	$373,154.00
14. Distribution	$3,216,028.00	$75,941.00	$3,291,969.00
15. Administrative and General	$3,290,872.00	$559,428.00	$3,850,300.00
16. Total Maint	$18,030,961.00	$3,214,543.00	$21,245,504.00
Total Operation and Maintenance			
18. Total Production (Lines 3 and 12)	$32,767,738.00	$7,321,749.00	$40,089,487.00
19. Total Transmission (Lines 4 and 13)	$2,998,757.00	$812,732.00	$3,811,489.00
20. Total Distribution (Lines 5 and 14)	$11,227,855.00	$1,266,267.00	$12,494,122.00
21. Customer Accounts (Transcribe from Line 6)	$3,440,063.00	$934,022.00	$4,374,085.00
22. Customer Service and Informational (Transcribe from Line 7)	$670,472.00	$168,931.00	$839,403.00
23. Sales (Transcribe from Line 8)	$0.00	$0.00	$0.00
24. Administrative and Generatl (Lines 9 and 15)	$16,000,329.00	$6,589,069.00	$22,589,398.00

Distribution of Salaries and Wages - Electric (Ref Page: 355)

	Specify	Direct Payroll (b)	Alloc Clearing Accts (c)	Total (d)
25. Total Oper. and Maint. (Lines 18-24)		$67,105,214.00	$17,092,770.00	$84,197,984.00

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Distribution of Salaries and Wages - Gas (Ref Page: 355)

Specify	Direct Payroll (b)	Alloc Clearing Accts (c)	Total (d)
Gas			
Operation			
28. Production -- Manufactured Gas			
29. Production -- Nat. Gas (Including Expl and Dev.)			
20. Other Gas Supply	$488,981.00	$127,185.00	$616,166.00
31. Storage, LNG Terminaling and Processing	$1,609,976.00	$371,511.00	$1,981,487.00
32. Transmission	$420,405.00	$101,833.00	$522,238.00
33. Distribution	$3,051,658.00	$1,059,942.00	$4,111,600.00
34. Customer Accounts	$2,814,445.00	$764,168.00	$3,578,613.00
35. Customer Service and Informational	$256,661.00	$75,845.00	$332,506.00
36. Sales	$0.00	$0.00	$0.00
37. Administrative and General	$3,011,211.00	$1,717,040.00	$4,728,251.00
38. Total Operation	$11,653,337.00	$4,217,524.00	$15,870,861.00
Maintenance			
40. Production -- Manufactured Gas	$0.00	$0.00	$0.00
41. Production -- Natural Gas	$0.00	$0.00	$0.00
42. Other Gas Supply	$0.00	$0.00	$0.00
43. Storage, LNG Terminaling and Processing	$1,187,267.00	$283,285.00	$1,470,552.00
44. Transmission	$166,207.00	$28,189.00	$194,396.00
45. Distribution	$4,602,226.00	$1,003,131.00	$5,605,357.00
46. Administrative and General	$1,344,108.00	$751,641.00	$2,095,749.00
47. Total Maint	$7,299,808.00	$2,066,246.00	$9,366,054.00
Total Operation and Maintenance			

Distribution of Salaries and Wages - Gas (Ref Page: 355)

Specify	Direct Payroll (b)	Alloc Clearing Accts (c)	Total (d)
50. Total Production -- Manufactured Gas (Lines 28 and 40)	$0.00	$0.00	$0.00
51. Total Production -- Natural Gas (Lines 29 and 41)	$0.00	$0.00	$0.00
52. Total Other Gas Supply (Lines 30 and 42)	$488,981.00	$127,185.00	$616,166.00
53. Total Storage LNG Terminaling and Processing (Lines 31 and 43)	$2,797,243.00	$654,796.00	$3,452,039.00
54. Total Transmission (Lines 32 and 44)	$586,612.00	$130,022.00	$716,634.00
55. Total Distribution (Lines 33 and 45)	$7,653,884.00	$2,063,073.00	$9,716,957.00
56. Customer Accounts (Transcribe Line 34)	$2,814,445.00	$764,168.00	$3,578,613.00
57. Customer Service and Informational (Transcribe Line 35)	$256,661.00	$75,845.00	$332,506.00
58. Sales (Transcribe Line 36)	$0.00	$0.00	$0.00
59. Administrative and General (Line 37 + 46)	$4,355,319.00	$2,468,681.00	$6,824,000.00
60. Total Operation and Maint (Lines 50-59)	$18,953,145.00	$6,283,770.00	$25,236,915.00
Other Utility Departments			
62. Operation and Maintenance	$0.00	$0.00	$0.00
63. Total All Utility Dept (Lines 25,60,62)	$86,058,359.00	$23,376,540.00	$109,434,899.00

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Distribution of Salaries and Wages - Utility Plant (Ref Page: 356)

	Specify	Direct Payroll (b)	Alloc Clearing Accts (c)	Total (d)
Utility Plant				
Construction (By Utility Departments)				
66. Electric Plant		$7,863,783.00	$7,010,624.00	$14,874,407.00
67. Gas Plant		$3,079,908.00	$3,913,281.00	$6,993,189.00
68. Other	Common Utility Plant	$1,318,608.00	$449,761.00	$1,768,369.00
69. Total Construction		$12,262,299.00	$11,373,666.00	$23,635,965.00
70. Plant Removal (By Utility Departments)				
71. Electric Plant		$1,038,349.00	$660,138.00	$1,698,487.00
72. Gas Plant		$187,466.00	$122,392.00	$309,858.00
73. Other	Common Utility Plant	$1,789.00	$664.00	$2,453.00
74. Total Plant Removal		$1,227,604.00	$783,194.00	$2,010,798.00
75. Other Accounts				
	Accounts Receivable (work done for others)	$6,008,094.00	$1,570,655.00	$7,578,749.00
	Miscellaneous Deferred Debits	$34,829.00	$838,317.00	$873,146.00
	Certain Civic Political & Related Activities & Otr	$451,538.00	$153,210.00	$604,748.00
	Acct Rec. (Non-Jurisdictional - Trimble County)	$1,411,813.00	$394,429.00	$1,806,242.00
76. Total Other Accounts		$7,906,274.00	$2,956,611.00	$10,862,885.00
77. Total Salaries and Wages		$107,454,536.00	$38,490,011.00	$145,944,547.00

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Charges for Outside Professional and Other Consultative Services (Ref Page: 358)

Description (a)	* (b)	Amount (2)
ACCENTURE LLP		$446,540.00
ACCU READ SERVICES		$3,613,001.00
ADVANCED ELECTRICAL SYSTEMS INC		$454,424.00
BAKER HUGHES BUSINESS SUPPORT SERVICES		$454,549.00
BELLOMY RESEARCH INC		$402,505.00
BURNESS DRILLING CORP		$306,449.00
CREATIVE ALLIANCE		$725,106.00
DEWEY AND LEBOEUF LLP		$256,140.00
DYNAMIC RISK ASSESSMENT SYSTEMS INC		$325,118.00
ENERGY ECONOMICS INC		$2,543,564.00
ENERGY MANAGEMENT AND SERVICES CO		$908,626.00
EVANS CONSTRUCTION CO INC		$323,088.00
FISHEL CO		$476,024.00
HONEYWELL INTERNATIONAL INC		$422,888.00
J Y LEGNER ASSOCIATES INC		$651,601.00
MILLER PIPELINE CORP		$15,957,563.00
OFF DUTY POLICE SERVICES INC		$747,958.00
OPS PLUS INC		$668,967.00
ROSEN USA		$372,240.00
SAMAC PAINTING INC		$539,583.00
SOUTHERN PIPELINE CONST CO		$3,421,127.00
STOLL CONSTRUCTION AND PAVING CO INC		$1,539,721.00
SURVEYS AND ANALYSIS INC		$1,105,695.00
TEK SYSTEMS		$425,620.00
TODAYS OFFICE PROFESSIONALS		$753,612.00
US BANK NATIONAL ASSOCIATION ND		$468,866.00

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Charges for Outside Professional and Other Consultative Services (Ref Page: 358)

Description (a)	* (b)	Amount (2)
USIC LOCATING SERVICES INC		$1,045,725.00
VENTYX INC		$780,523.00
XEROX CORP		$757,527.00
Total		$40,894,350.00

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Compressor Stations (Ref Page: 508)

Name of Station and	Number of Units (b)	Certified Horsepower (c)	Plant Cost (d)	Fuel or Power (e)	Fuel or Power Type
Underground Storage:	0	0	$0.00	$0.00	
Magnolia - Magnolia, Ky.	6	8,010	$11,688,725.00	$583,938.00	Natural Gas
Muldraugh - Muldraugh, Ky.	9	9,550	$23,945,403.00	$46,142.00	Natural Gas
0	0	0	$0.00	$0.00	
Field Compressor Stations for Self-Use to Recover	0	0	$0.00	$0.00	
Underground Storage Gas:	0	0	$0.00	$0.00	
Doe Run - Brandenburg, Ky. and Laconia, In.	9	1,035	$9,730,869.00	$118,737.00	See Footnote
Muldraugh - Muldraugh, Ky.	1	30	$110,905.00	$756.00	Electricity

Compressor Stations (Ref Page: 508) (Part Two)

Name of Station and	Other (f)	Gas for Comp Fuel MCF	Total Comp Hours	Comp operating at Time	Date of Station Peak (j)
Underground Storage:	$0.00	0	0	0	
Magnolia - Magnolia, Ky.	$1,487,975.00	120,070	12,414	4	12/24/2011
Muldraugh - Muldraugh, Ky.	$1,915,654.00	8,709	858	0	02/22/2011
0	$0.00	0	0	0	
Field Compressor Stations for Self-Use to Recover	$0.00	0	0	0	
Underground Storage Gas:	$0.00	0	0	0	
Doe Run - Brandenburg, Ky. and Laconia, In.	$1,465,644.00	2,376	20,496	0	
Muldraugh - Muldraugh, Ky.	$0.00	0	1,800	0	

Note:
Field Compressor Stations:

Doe Run - Brandenburg, Ky. and Laconia, In., column (b):
Of the total, five compressors were not operated during 2011.

Doe Run - Brandenburg, Ky. and Laconia, In., column (c):
Of the total amount, 615 horsepower was non-operational during 2011.

Doe Run - Brandenburg, Ky. and Laconia, In., column (e):
Of the total amount, $11,483 is gas and $107,254 is electricity.

Doe Run - Brandenburg, Ky. and Laconia, In., column (j):
Station Peak not applicable for field compressors.

Muldraugh - Muldraugh, Ky., column (d):
Of this total, approximately $25,000 is the cost of a replaced asset which will be retired.

Muldraugh - Muldraugh, Ky., column (j):
Station Peak not applicable for field compressors.

Gas Storage Projects (Ref Page: 512)

	Gas Belonging to Respondent MCF (b)	Gas Belonging to Others MCF (c)	Total MCF (d)
Storage Operations (in MCF)			
Gas Delivered to Storage			
January	0	0	0
February	0	0	0
March	0	0	0
April	10,253	0	10,253
May	0	0	0
June	1,253,597	0	1,253,597
July	2,669,456	0	2,669,456
August	3,006,615	0	3,006,615
September	2,782,756	0	2,782,756
October	2,224,981	0	2,224,981
November	108,435	0	108,435
December	6,025	0	6,025
Total	12,062,118	0	12,062,118
Gas Withdrawn from Storage			
January	3,276,581	0	3,276,581
February	2,844,904	0	2,844,904
March	1,983,775	0	1,983,775
April	1,017,732	0	1,017,732
May	380,093	0	380,093
June	367	0	367
July	423	0	423
August	461	0	461
September	429	0	429
October	1,253	0	1,253
November	815,869	0	815,869

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Gas Storage Projects (Ref Page: 512)

	Gas Belonging to Respondent MCF (b)	Gas Belonging to Others MCF (c)	Total MCF (d)
December	1,975,679	0	1,975,679
Total	12,297,566	0	12,297,566

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Gas Storage Projects (cont) (Ref Page: 513)

	Total Amount (b)	Date
Storage Operations		
Top or Working Gas End of Year	11,466,101	
Cushion Gas (Including native gas)	10,810,000	
Total Gas in Reservoir	22,276,101	
Certified Storage Capacity	25,900,000	
Number of Injection - Withdrawal Wells	360	
Number of Obsevation Wells	141	
Maximum Days Withdrawal from Storage	153,648	
Date of Maximum Days Withdrawal		02/02/2011
LNG Terminal Companies (MCF)		
Number of Tanks		
Capacity of Tanks		
LNG Volume		
Received at Ship Rail		
Transferred to Tanks		
Withdrawn from Tanks		
Boil Off Vaporization Loss		

Note:
Cushion Gas includes non-current base gas of 2,930,000 Mcf (Account 117).

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Transmission Lines (Ref Page: 514)

Designation of Line or Group of Lines (a)	* (b)	Total Miles of Pipe (c)
Western Kentucky Line		49
Magnolia Line		121
Calvary Line		57
Elder Park Line		27
Total		254

Note:
The amounts reported on this page exclude gas transmission storage lines, gas combustion turbine lines and gas transmission pipeline in regular facilities.

Transmission System Peak Deliveries (Ref Page: 518)

	Description	MCF Gas to Interstate Pipelines (b)	MCF Gas to Others (c)	Total (d)
Section A: Single Day Peak Deliveries				
Date	January 13, 2012			
Volumes of Gas Transported				
No-Notice Transportation		0	81,000	0
Other Firm Transportation		0	59,000	0
Interruptible Transportation		0	0	0
Other (Describe)				
	End-use Transportation	0	51,000	0
Total		0	191,000	0
Volumes of gas Withdrawn form Storage under Storage Contracts				
No-Notice Storage		0	55,000	0
Other Firm Storage		0	0	0
Interruptible Storage		0	0	0
Other (Describe)				
Total		0	55,000	0
Other Operational Activities				
Gas Withdrawn from Storage for System Operations		0	126,000	0
Reduction in Line Pack		0	0	0
Other (Describe)				
Total		0	126,000	0
Section B: Consecutive Three-Day Peak Deliveries				
Dates:	January 12, 13, 14, 2012			
Volumes of Gas Transported				

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Transmission System Peak Deliveries (Ref Page: 518)

Description	MCF Gas to Interstate Pipelines (b)	MCF Gas to Others (c)	Total (d)
No-Notice Transportation	0	172,000	0
Other Firm Transportation	0	176,000	0
Interruptible Transportation	0	0	0
Other (Describe)			
End-use Transportation	0	144,000	0
Total	0	492,000	0
Volumes of Gas Withdrawn from Storage under Storage Contacts			
No-Notice Storage	0	160,000	0
Other Firm Storage	0	0	0
Interruptible Storage	0	0	0
Other (Describe)			
Total	0	160,000	0
Other Operational Activities			
Gas Withdrawn from Storage for System Operations	0	363,000	0
Reduction in Line Pack	0	0	0
Other (Describe)			
Total	0	363,000	0

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Auxiliary Peaking Facilities (Ref Page: 519)

Location (a)	Type (b)	Max Daily Delivery Capacity MCF (c)	Cost of Facility (d)	Operated on Date Highest Trans Peak Del? (yes/no)
Muldraugh - Meade County, Ky	Underground Storage	220,000	$27,177,160.00	Yes
Doe Run - Meade Co., Ky. & Harrison Co., Ind.	Underground Storage	53,115	$9,730,869.00	Yes
Magnolia - Green, Hart and Larue Counties, Ky.	Underground Storage	59,798	$29,318,457.00	Yes
Center - Metcalfe, Green and Barren Counties, Ky.	Underground Storage	10,795	$9,045,691.00	Yes
Canmer - Hart and Green Counties, Ky.		0	$348,066.00	
Flint Hill - Hardin County, Ky.		0	$273,275.00	
TOTAL		330,593	$75,893,518.00	

Note:
(1) Gas fields at Canmer and Flint Hill have been retired. These facilities are currently used in other gas-system operations.

(2) Due to pipeline and compressor capacity and multiple fields discharging into one pipeline system, overall system delivery has been estimated at this figure, even though individual fields may have greater deliverability than shown, and may aggregate to a higher total, especially earlier in the season, when operated independently.

22200500 Louisville Gas and Electric Company 01/01/2011 - 12/31/2011

Gas Account - Natural Gas (Ref Page: 520)

Description	Amt MCF
GAS RECEIVED	
Gas Purchases (800-805)	32,928,858
Gas of Others received for Gathering (ref pg 303) (489.1)	
Gas of Others Received for Transmission (Ref pg 305) (489.2)	
Gas of Others Received for Distrubution (ref pg 301) (489.3)	11,909,306
Gas of Others Received for Contract Storage (Ref Pg 307) (489.4)	
Exchanged Gas Received from Others (Ref Pg 328) (806)	3,011,204
Gas Received as Imbalances (Ref Pg 328) (806)	
Receipts of Respondent`s Gas Transported by Others (Ref pg 332) (858)	
Other Gas Withdrawn from Storage (Explain)	12,297,566
Gas Received from Shippers as Compressor Station Fuel	
Gas Received from Shippers as Lost and Unaccounted for	
Other Reciepts (Specify)	
Total Receipts	60,146,934
GAS DELIVERED	
Gas Sales (480-484)	31,130,203
Deliveries of gas Gathered for Others (Ref pg 303) (489.1)	
Deliveries of Gas Transported for Others (Ref Pg 305) (489.2)	336,775
Deliveries of Gas Distributed for Others (Ref Pg 301) (489.3)	11,242,723
Deliveries of Contract Storage gas (Ref Pg 307) (489.4)	
Exchange Gas Delivered to Others (Ref Pg 328) (806)	3,256,898
Gas Delivered as Imbalances (Ref Pg 328) (806)	
Deliveries of Gas to Others for Transportation (Ref Pg 332) (858)	
Other Gas Delivered to Storage (Explain)	12,062,118

Gas Account - Natural Gas (Ref Page: 520)

	Description	Amt MCF
Gas Used for Compressor Station Fuel (509)		128,781
Other Deliveries (Specify)		
	Duplicate Charges (Gas Department)	120,626
	Gas Used for Other Utility Operations	21,976
28. Total Deliveries		58,300,100
GAS UNACCOUNTED FOR		
Production System Losses		
Gathering System Losses		
Transmission System Losses		
Distribution System Losses		
Storage System Losses		461,740
Other Losses (Specify)		
	Sales and Transport	1,436,702
36. Total Unaccounted For		1,898,442
Total Deliveries and Unaccounted For For (Line 28 and 36)		60,198,542

Note:
Gas purchases include volumes recorded in Natural gas transmission line purchases (803).

Transmission gas is reported on the following lines:
Gas of Others Recieved for Distribution - 11,909,306 MCF
Deliveries of Gas Transported for Others - 336,775 MCF
Deliveries of Gas Distributed for Others - 11,242,723 MCF

Other Gas Withdrawn from Storage represents net withdrawal of gas from storage recorded in Gas withdrawn from storage-- Debit (808.1).

Other Gas Delivered to Storage represents net deliveries of gas to storage recorded in Gas delivered to storage--Credit (808.2).

CheckList

Item	Value 1	Value 2	Agree	Explain
Balance Sheet (Ref pg 110)				
Utility Plant agrees with Sched Summary of Utility Plant (Ref pg 200) Line 13. Total Utility Plant less Line 11. Construction Work In Progress	4679879565.00	4679879565.00	OK	
Line 3. Construction Work In Progress agrees with Sched Summary of Utility Plant (Ref pg 200) Line 11. Construction Work In Progress	215276377.00	215276377.00	OK	
Line 5. Accum. Prov for Depr and Amort Depl agrees with Sched Summary of Utility Plant (Ref Pg 200) Lines 14. Accum. Prov for Depr and Amort Depl	2117873453.00	2117873453.00	OK	
Line 5. Accum. Prov for Depr and Amort Depl agrees with Sched Summary of Utility Plant (Ref Pg 200) Lines 33. Total Accumulated Provisions	2117873453.00	2117873453.00	OK	
Line 6. Net Utility Plant agrees with Sched Summary of Utility Plant (Ref Pg 200) Lines 15. Net Utility Plant	2777282489.00	2777282489.00	OK	
Line 11. Utility Plant Adjustments are supported by Submitted Financial Statements as requested on Ref Pg 122				
Line 12. Gas Stored-Base Gas (117.1) agrees with Sched Gas Stored Accounts (Ref Pg 220) Line Balance at End of Year Column 117.1 (b)	2139990.00	2139990.00	OK	
Line 14. Gas Stored Underground - Non Current (117.3) agrees with Sched Gas Stored Accounts (Ref Pg 220) Line Balance at End of Year Column 117.4 (d)	0.0000	0.0000	OK	
Line 15. Gas Owned to System Gas (117.4) agrees with Sched Gas Stored Accounts (Ref Pg 220) Line Balance at End of Year Column 117.4 (e)	0.0000	0.0000	OK	
Line 17. Investments in Subsidiary Companies agrees with Sched Investments in Subsidiary Companies 123.1 (Ref Pg 224) Line Total Column Amt of Investment (g)	594286.00	594286.00	OK	
Line 47. Gas Stored Underground - Current (164.1) agrees with Sched Gas Stored Accounts (Ref Pg 220) Col 164.1 (f)	53287604.00	53287604.00	OK	

CheckList

Item	Value 1	Value 2	Agree	Explain
Line 48. Liquefied Nat Gas Stored and Held (164.3) agrees with Sched Gas Stored Accounts (Ref Pg 220) Sum of Cols 164.2 and 164.3	0.0000	0.0000	OK	
Line 49. Prepayments agrees with Sched Prepayments (Ref Pg 230)	5472353.00	5472353.00	OK	
Line 58. Extraordinary Property Losses agrees with Sched Extraordinary Property Losses (Ref Pg 230)	0.0000	0.0000	OK	
Line 59 Unrecovered Plant and Regulatory Study Costs agrees with Sched Unrecovered Plant and Regulatory Study Costs (Ref Pg 230)	0.0000	0.0000	OK	
Line 65 Miscellaneous Deferred Debits agrees with Sched Miscellaneous Deferred Debits (Ref Pg 233)	550300832.00	550300832.00	OK	
Line 69 Accumulated Deferred Income Taxes agrees with Sched Accumulated Deferred Income Taxes (Ref Pg 234) Total Acct 190	90900667.00	90900667.00	OK	
Comparative Balance Sheet (Liabilities and Other Credits) (Ref Pg 112)				
Line 2. Common Stock Issued agrees with Sched Capital Stock (Ref Pg 250) Line Total Common Stock Col (f)	425170424.00	425170424.00	OK	
Line 3. Preferred Stock Issued agrees with Sched Capital Stock (Ref Pg 250) Line Total Preferred Stock Col (f)	0.0000	0.0000	OK	
Line 4. Capital Stock Subscribed agrees with Sched Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Pg 252) Line Total Capital Stock Subscribed Col (d)	0.0000	0	OK	
Line 5. Stock Liability for Conversion agrees with Sched Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Pg 252) Line Total Stock Liability for Conversion	0.0000	0	OK	

CheckList

Item	Value 1	Value 2	Agree	Explain
Line 6. Premium on Capital Stock agrees with Sched Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Pg 252) Line Total Premium on Capital Stock	0.0000	0	OK	
Line 7. Other Paid-in Capital Stock agrees with Sched Other Paid in Capital(Ref Pg 253) Line Total	1277667368.00	1277667368.00	OK	
Line 8 . Installmnts Recvd Capital Stk agrees with Sched Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Pg 252) Line Tot Inst. Recvd on Capital Stock	0.0000	0	OK	
Line 9. Discount on Capital Stock agrees with Sched Discount on Capital Stock Acct 213 (Ref Pg 254) Line Total	0.0000	0	OK	
Line 10. Capital Stock Expense agrees with Sched Capital Stock Expense Acct 214 (Ref Pg 254) Line Total	835889.00	835889.00	OK	
Line 11 Retained Earnings agrees with Statement of Retained Earnings for the Year (Ref Pg 118) Line 19. Total Retained Earnings	60196667.00	60196667.00	OK	
Line 12. Unappropriated Undistributed Subsidiary Earnings agrees with Statement of Retained Earnings for the Year (Ref Pg 118) Line 24. Balance End of Year	0.0000	0	OK	
Line 13. Reacquired Capital Stock agrees with Capital Stock (Ref Pg 250) Line Total col Acct 217 (h)	0.0000	0.0000	OK	
Line 39. Taxes Accrued agrees with Sched Taxes Accrued, Prepaid and Charged (Ref Pg 263) Line Total Col Acct 236 (g)	13284850.00	13284850.00	OK	
Line 45. Misc Current and Accrued Liabilities agrees with Sched Misc Current and Accured Liabilities (Ref Pg 268) Line Total	16535301.00	16535301.00	OK	
Line 52. Other Deferred Credits agrees with Sched Other Deferred Credits (Ref Pg 269) Line Total	10652321.00	10652321.00	OK	
Income Statement (Ref Pg 114)				

CheckList

Item	Value 1	Value 2	Agree	Explain
Line 2. Gas Operating Revenues agrees with Sched Gas Operating Revenues (Ref Pg 300) Line Total Col (h)	304574422.00	304574422.00	OK	
Sum of Lines 4 and 5 Operation and Maint Expenses agrees with Sched Gas Operation and Maintenance (Ref Pg 335) Line Total Gas O and M Expenses	226091937.00	226091937.00	OK	
Line 6. Depreciation Exp (403) agrees with Sched Depreciation, Depletion and Amort (Ref Pg 336) Line Total Col Depreciation (b)	20052940.00	20052940.00	OK	
Line 7. Amort and Depl (404-405) agrees with Sched Depreciation, Depletion and Amort (Ref Pg 336) Line Total Sum of Cols (c-f)	2358705.00	2358705.0000	OK	
Sum of Lines 13,14 and 15. Taxes (408.1-409.1) agrees with Sched Taxes Accr, Prepd and Charged (Ref Pg 262) Line Total Col (j)	-10671457.00	-10671457.00	OK	
Line 16. Provision for Deferred Income Taxes (410.1) agrees with SUM OF Acct 190 (Ref Pg 234) Col c , Acct 282 (Ref Pg 274) Col c and Acct 282 (Ref Pg 276) Col c	253017989.00	253017989.00	OK	
Line 17. (Less) Provision for Deferred Income Taxes (411.1) agrees with SUM OF Acct 190 (Ref Pg 234) Col d , Acct 282 (Ref Pg 274) Col d and Acct 282 (Ref Pg 276) Col d	198676654.00	198676654.00	OK	
Income Statement (Ref Pg 116)				
Sum of Lines 48,49 and 50 agrees with Sched Taxes Accr, Prepd and Charged (Ref Pg 262) Line Total Taxes Other Than Income Col (l)	-576264.00	-576264.00	OK	
Line 49. Provision for Deferred Inc. Taxes agrees with Sched Accumulated Deferred Income Taxes (Ref Pg 234) Line Total Acct 190 Col 410.2 (e)	2320167.00	139696.00	NO	The difference between the provision for Deferred Income Taxes per the Income Statment and the Schedule of Accumulated Deferred Income Taxes of $2,180,471 is in Account 283 (Ref Pg 276).
Line 52. (Less) Provision for Deferred Inc. Taxes CR agrees with Sched Accumulated Deferred Income Taxes (Ref Pg 234) Line Total Acct 190 Col 411.2 (f)	2494859.00	314388.00	NO	The difference between the provision for Deferred Income Taxes per the Income Statment and the Schedule of Accumulated Deferred Income Taxes of $2,180,471 is in Account 283 (Ref Pg 276).

CheckList

Item	Value 1	Value 2	Agree	Explain
Line 70. Income Taxes - Federal and Other agrees with Sched Taxes Accr, Prepd and Charged (Ref Pg 262) Col 409.3 (m) Sum of Lines Total Income Taxes Federal and Other	0.0000	0.0000	OK	
Summary of Utility Plant and Accumulated Provisions for Depreciation Amortization and Depletion (Ref Pg 200)				
Line 8. Total Utility Plant agrees with Sched Gas Plant in Service (Ref Pg 206) Line Total Gas Plant in Service Col (g)	724381115.00	724381115.00	OK	
Line 10. Held for Future Use agrees with Sched Gas Plant Held for Future Use (Ref Pg 214) Line Total	0.0000	0	OK	
Line 11. Construction Work in Progress agrees with Sched Construction Work in Progress (Ref Pg 216) Line Total	47481610.00	47481610.00	OK	
Line 18. Depreciation agrees with Sched Accumulated Provision for Depreciation of Gas Utility Plant (Ref Pg 219) Line Balance at End of Year	236679884.00	236679884.00	OK	
Statement of Retained Earnings for the Year (Ref Pg 118)				
Line 10 Total Dividends Declared - Preferred Stock agrees with Statement of Cash Flows (Ref Pg 120) Line 68. Dividends on Preferred Stock	0	0	OK	
Line 11. Total Dividends Declared - Common Stock agrees with Statement of Cash Flows (Ref Pg 120) Line 69. Dividends on Common Stock	-83250000.00	-83250000.00	OK	
Miscellaneous General Expenses (Ref Pg 335)				
Line Total agrees with Sched Gas Operation and Maintenance (Ref Pg 323) Line Miscellaneous General Expenses	118822.00	118822.00	OK	

Notes to Financial Statements

Per Kentucky PSC Order No. 2008-00007, attached are the "Notes to Financial Statements" for Louisville Gas & Electric Company as reported in the FERC Form No. 1 for the period ended December 31, 2011.

GLOSSARY OF TERMS AND ABBREVIATIONS

KU **-** Kentucky Utilities Company, a public utility affiliate of LG&E and 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 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 LG&E, KU 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 LG&E, 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 LG&E (Registration No. 333-173676) 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.

AOCI **-** accumulated other comprehensive income or loss.

ARO **-** asset retirement obligation.

Bluegrass CTs **-** Three natural gas combustion turbines owned by Bluegrass Generation. LG&E and KU 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.

***EBPB* -** Employee Benefit Plan Board. The administrator of PPL's U.S. qualified retirement plans, which is charged with the fiduciary responsibility to oversee and manage those plans and the investments associated with those plans.

***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.

***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.

***Fitch* -** Fitch, Inc., a credit rating agency.

***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.

kWh **-** kilowatt-hour, basic unit of electrical energy.

LG&E 2010 Mortgage Indenture **-** LG&E's Indenture, dated as of October 1, 2010, to The Bank of New York Mellon, as trustee, as supplemented.

LIBOR **-** London Interbank Offered Rate.

MATS - Mercury and Air Toxics Standards.

Moody's **-** Moody's Investors Service, Inc., a credit rating agency.

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.

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 LG&E pre-acquisition activity covering the time period prior to November 1, 2010.

S&P **-** Standard & Poor's Ratings Services, a credit rating agency.

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 LG&E 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.

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.

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

LG&E is engaged in the regulated generation, transmission, distribution and sale of electricity. LG&E also engages in the regulated distribution and sale of natural gas.

The financial statements and accompanying footnotes of LG&E 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 LG&E 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 LG&E 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. LG&E consolidates a VIE when it is determined to have a controlling interest in the VIE, and thus is the primary beneficiary of the entity. LG&E 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. . Any noncontrolling interests are reflected in the financial statements.

The financial statements of LG&E 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

LG&E is a cost-based rate-regulated utility for which rates are set by regulators to enable LG&E to recover the costs of providing electric or gas 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." LG&E 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 LG&E's net income or equity.

Comprehensive Income

Comprehensive income includes net income and OCI. Comprehensive income is shown on the Statements of Comprehensive Income.

LG&E had an AOCI balance of $(10) million at December 31, 2009 (Predecessor period). During the ten months ended October 31, 2010 (a Predecessor period), LG&E had $10 million of after-tax gains on qualifying derivatives. There were no AOCI balances at December 31, 2010 and 2011 (Successor periods).

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. Interest rate contracts are used to hedge exposures to changes in the fair value of debt instruments and to hedge exposures to variability in expected cash flows associated with existing debt instruments or forecasted issuances of debt. 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, gas storage 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.

A similar process is also followed by the treasury department as it relates to interest rate derivatives. Examples of accounting guidelines provided to the treasury department staff include, but are not limited to:

- Transactions to lock in an interest rate prior to a debt issuance can be designated as cash flow hedges.
- Transactions entered into to hedge fluctuations in the fair value of existing debt can be designated as fair value hedges.
- Derivative transactions may be marked to fair value through regulatory assets/liabilities if approved by the appropriate regulatory body. These transactions generally include the effect of interest rate swaps that are included in customer rates.

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.

LG&E 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.

<u>Revenue Recognition</u>

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:

		Additions			
	Balance at Beginning of Period	**Charged to Income**	**Charged to Other Accounts (a)**	**Deductions (b)**	**Balance at End of Period**
2011 - Successor	$ 2	$ 5	$ -	$ 5	$ 2
2010 - Successor	-	1	2	1	2
2010 - Predecessor	2	4	-	4	2

(a) Primarily related to capital projects, thus the provision was recorded as an adjustment to construction work in progress.
(b) Includes amounts associated with LG&E 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 LG&E while the noncurrent portion is included in "Other noncurrent assets." At December 31, the balances of restricted cash and cash equivalents included the following.

	2011	2010
Margin deposits posted to counterparties (a)	$ -	$ 3
Cash collateral posted to counterparties (b)	29	19
Other	-	-
Total	$ 29	$ 22

(a) Deposits posted to counterparties associated with trading activities.
(b) Cash collateral posted to counterparties related to interest rate swap contracts.

Fair Value Measurements

LG&E 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. LG&E 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.

LG&E 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, LG&E'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.

Cost Method Investment

LG&E has an investment in OVEC, which is accounted for using the cost method. The investment is recorded in "Other noncurrent assets" on the LG&E Balance Sheet. LG&E 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 LG&E and 12 other companies affiliated with the various owners. LG&E owns 5.63% of OVEC's common stock. Pursuant to a power purchase agreement, LG&E is contractually entitled to its ownership percentage of OVEC's output, which is 134 MW.

LG&E’s investment in OVEC is not significant. The direct exposure to loss as a result of LG&E's involvement with OVEC is generally limited to the value of its investment; however, LG&E 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. LG&E records costs associated with planned major maintenance projects in the period in which the costs are incurred. LG&E 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.

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**
$ 52	$ 9	$ 44	$ 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**
$ 8	$ 1	$ 7

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 5.11% and 5.40% 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 LG&E'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, LG&E 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.

LG&E accounts for emission allowances as intangible assets. LG&E 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. LG&E 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

LG&E 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 LG&E, 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

LG&E 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 LG&E'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

LG&E sponsors and participates in qualified funded defined benefit pension plans and participates in a funded other postretirement benefit plan. These plans are applicable to the majority of the employees of LG&E. The plans LG&E participates in are sponsored by LKE. LKE allocates a portion of the liability and net periodic defined benefit pension and other postretirement costs of certain plans to LG&E based on its participation. LG&E 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.

LG&E and LKE use 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

LG&E is included in PPL's consolidated U.S. federal income tax return. Prior to PPL's acquisition of LKE, LG&E was included in E.ON US Investments Corp.'s consolidated U.S. federal income tax return.

Significant management judgment is required in developing LG&E'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. LG&E 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 LG&E 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.

LG&E records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. LG&E 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 LG&E 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 LG&E 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.

LG&E defers investment tax credits when the credits are utilized and amortizes the deferred amounts over the average lives of the related assets.

LG&E 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 LG&E is calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if LG&E 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. LG&E's intercompany tax receivable was $4 million at December 31, 2011 and 2010.

The provision for LG&E’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

LG&E 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

LG&E evaluates whether arrangements entered into contain leases for accounting purposes. See Note 8 for a discussion of arrangements under which LG&E is a lessee for accounting purposes.

Fuel, Materials and Supplies

Fuel, natural gas stored underground 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. For LG&E, natural gas supply costs are charged to expense as delivered to the distribution system. See Note 4 for further discussion of the fuel adjustment clause and gas supply clause.

"Fuel, materials and supplies" on the Balance Sheets consisted of the following at December 31.

	2011		2010	
Fuel	$	53	$	68
Natural gas stored underground (a)		53		60
Materials and supplies		36		34
Total	$	142	$	162

(a) The majority of LG&E's natural gas stored underground is held to serve native load.

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, LG&E 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.

LG&E 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 LG&E.

2. Preferred Securities

LG&E is authorized to issue up to 1,720,000 shares of preferred stock at a $25 par value and 6,750,000 shares of preferred stock without par value. LG&E had no preferred stock issued or outstanding in 2011 or 2010.

3. Income and Other Taxes

The provision for LG&E's deferred income taxes for regulated assets is based upon the ratemaking principles reflected in rates established by the KPSC 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 LG&E's deferred income tax assets and liabilities were as follows:

	2011	2010
Deferred Tax Assets		
Regulatory liabilities and other	$ 65	$ 86
Deferred investment tax credit (a)	17	8
Income taxes due to customers	23	25
Liabilities and other	10	10
Total deferred tax assets	115	129
Deferred Tax Liabilities		
Plant - net	462	422
Regulatory assets and other	107	108
Accrued pension costs	19	16
Total deferred tax liabilities	588	546
Net deferred tax liability	$ 473	$ 417

(a) Changes in balance primarily relate to investment tax credits for TC2, which began dispatching electricity in January 2011. See discussion on TC2 below.

LG&E 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	$ 12	$ (4)
Current - State	8	1
Total Current Expense	20	(3)
Deferred - Federal	52	12
Deferred - State	2	1
Total Deferred Expense	54	13
Investment tax credit, net - Federal	(3)	-
Total income tax expense (a)	$ 71	$ 10
Total income tax expense - Federal	$ 61	$ 8
Total income tax expense - State	10	2
Total income tax expense (a)	$ 71	$ 10

	Predecessor
	Ten Months Ended October 31, 2010
Income Tax Expense (Benefit)	
Current - Federal	$ 32
Current - State	5
Total Current Expense	37
Deferred - Federal	21
Deferred - State	2
Total Deferred Expense	23
Investment tax credit, net - Federal	(2)
Total income tax expense (a)	$ 58
Total income tax expense - Federal	$ 51
Total income tax expense - State	7
Total income tax expense (a)	$ 58

(a) Excludes deferred federal and state tax expense recorded to OCI of $7 million for the ten month period ended October 31, 2010. Also excludes deferred federal and state tax expense recorded to Regulatory assets of $2 million in 2011, $1 million for the two month period ended December 31, 2010 and $6 million for the ten month period ended October 31, 2010.

	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%	$ 68	$ 10
Increase (decrease) due to:		
State income taxes, net of federal income tax benefit	7	1
Other	(4)	(1)
Total increase (decrease)	3	-
Total income tax expense	$ 71	$ 10
Effective income tax rate	36.4%	34.5%

	Predecessor
	Ten Months Ended October 31, 2010
Reconciliation of Income Taxes	
Federal income tax on Income Before Income Taxes at statutory tax rate - 35%	$ 58
Increase (decrease) due to:	
State income taxes, net of federal income tax benefit	4
Other	(4)
Total increase (decrease)	-
Total income tax expense	$ 58
Effective income tax rate	34.7%

	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	$ 18	$ 1	$ 12

In June 2006, LG&E and KU filed a joint application with the DOE requesting certification to be eligible for $125 million in investment tax credits ($24 million to LG&E and $101 million to KU) applicable to the construction of TC2. All necessary DOE and IRS approvals were subsequently received. In September 2007, LG&E and KU 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 LG&E and KU.

Unrecognized Tax Benefits

LG&E's unrecognized tax benefits and changes in those unrecognized tax benefits are insignificant at December 31, 2011 and 2010. For LG&E, 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 LG&E.

At December 31, 2011 and 2010, the receivable (payable) balances were recorded for interest related to tax positions. The amounts for LG&E were insignificant. The interest expense (benefit) was recognized in income taxes. The amount for LG&E was insignificant.

Tax Jurisdictions

The income tax provisions for LG&E 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. LG&E 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 LG&E, 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, LG&E 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.

LG&E is subject to the jurisdiction of the KPSC and FERC.

LG&E's 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. LG&E 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. LG&E's customer rates will continue to reflect the original contracted prices for these contracts.

The following tables provide information about the regulatory assets and liabilities of cost-based rate-regulated utility operations.

	2011	2010
Current Regulatory Assets:		
ECR	$ -	$ 5
Coal contracts (a)	-	1
Gas supply clause	6	4
Fuel adjustment clause	3	3
Total current regulatory assets	$ 9	$ 13
Noncurrent Regulatory Assets:		
Defined benefit plans	$ 225	$ 213
Storm costs	66	65
Unamortized loss on debt	21	22
Interest rate swaps	69	43
Coal contracts (a)	5	8
AROs	11	7
Other	6	9
Total noncurrent regulatory assets	$ 403	$ 367

Current Regulatory Liabilities:		
Coal contracts (a)	$ -	$ 31
Gas supply clause	6	9
Other	4	11
Total current regulatory liabilities	$ 10	$ 51
Noncurrent Regulatory Liabilities:		
Coal contracts (a)	$ 78	$ 87
Power purchase agreement - OVEC (a)	80	86
Net deferred tax assets	31	34
Other	3	1
Total noncurrent regulatory liabilities	$ 192	$ 208

(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, $21 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

LG&E has the ability to request from the KPSC 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, LG&E 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 2035 for LG&E.

ECR

Kentucky law permits LG&E 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. LG&E 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, LG&E'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.

Gas Supply Clause

LG&E's natural gas rates contain a gas supply clause, whereby the expected cost of natural gas supply and variances between actual and expected costs from prior periods are adjusted quarterly in LG&E's rates, subject to approval by the KPSC. The gas supply clause includes a separate natural gas procurement incentive mechanism, a performance-based rate, which allows LG&E's rates to be adjusted annually to share variances between actual costs and market indices between the shareholders and the customers during each performance-based rate year (12 months ending October 31). The regulatory assets or liabilities represent the total amounts that have been under- or over-recovered due to timing or adjustments to the mechanisms and are recovered within 18 months.

Fuel Adjustments

LG&E's retail electric 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 LG&E'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.

Interest Rate Swaps

Because realized amounts associated with LG&E's interest rate swaps, including a terminated swap contract, are recoverable through rates based on an Order from the KPSC, LG&E's unrealized gains and losses are recorded as a regulatory asset or liability until they are realized as interest expense. Interest expense from existing swaps is realized and recovered over the terms of the associated debt, which matures through 2033. Amortization of the gain/loss related to the terminated swap contract is recovered through 2035 as approved by the KPSC.

In the third quarter of 2010, LG&E recorded a pre-tax gain to reverse previously recorded losses of $21 million and $9 million to reflect the reclassification of its ineffective swaps and terminated swap to regulatory assets based on an Order from the KPSC in the 2010 rate case whereby the cost of LG&E's terminated swap was allowed to be recovered in base rates. Previously, gains and losses on interest rate swaps designated as effective cash flow hedges were recorded within other comprehensive income and common equity. The gains and losses on the ineffective portion of interest rate swaps designated as cash flow hedges were recorded to earnings monthly, as was the entire change in the market value of the ineffective swaps.

<u>AROs</u>

As noted in Note 1, the accretion and depreciation related to LG&E'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.

<u>DSM</u>

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. LG&E'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 LG&E 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.

<u>Power Purchase Agreement - OVEC</u>

As a result of purchase accounting associated with PPL's acquisition of LKE, LG&E'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.

<u>Regulatory Liability Associated with Net Deferred Tax Assets</u>

LG&E'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, LG&E 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. LG&E requested $1.4 billion to modernize the sulfur dioxide scrubbers at the Mill Creek generating plant as well as install fabric-filter baghouse systems for increased particulate and mercury control on all units at the Mill Creek generating plant and on Unit 1 at the Trimble County generating plant.

In November 2011, LG&E and KU filed a joint unanimous settlement agreement, stipulation and recommendation with the KPSC. In December 2011, LG&E and KU 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 LG&E and KU 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 $1.4 billion at LG&E and $900 million at KU. 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. 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, LG&E and KU 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. LG&E and KU are awaiting the KPSC Staff report, which will close this proceeding.

CPCN Filing

In September 2011, LG&E and KU filed a CPCN with the KPSC requesting approval to build a 640 MW

NGCC at the existing Cane Run plant site. LG&E will own a 22% undivided interest, and KU will own a 78% undivided interest in the new NGCC. In addition, LG&E and KU also requested approval to purchase the Bluegrass CTs which are expected to provide up to 495 MW of peak generation supply. LG&E will own a 69% undivided interest, and KU will own a 31% undivided interest in the purchased assets. In conjunction with these developments, at the end of 2015, LG&E anticipates retiring three coal-fired generating units at its Cane Run plant. These generating units represent 563 MW of combined summer capacity.

LG&E anticipates that the NGCC construction and the acquisition of the Bluegrass CTs could require up to $300 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 LG&E and KU would commit that no base rate increases would take effect before January 1, 2013. Under the terms of the settlement, LG&E and KU 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, LG&E and KU agreed to implement the Acquisition Savings Sharing Deferral (ASSD) methodology whereby LG&E's and KU's adjusted jurisdictional revenues, expenses, and net operating income are calculated each year. If LG&E's or KU'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, LG&E and KU have not recognized any impact of the ASSD in the financial statements as of December 31, 2011. The ASSD methodology for each of LG&E's and KU'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

LG&E operates under a FERC-approved open access transmission tariff. LG&E 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. LG&E 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 August 2011, a strong storm hit LG&E's service area causing significant damage and widespread outages for approximately 139,000 customers. LG&E filed an application with the KPSC in September 2011 requesting approval of a regulatory asset recorded to defer, for future recovery, $8 million in incremental operation and maintenance expenses related to the storm restoration. An Order was received in December 2011 granting regulatory accounting treatment, while recovery of the regulatory asset will be determined within the next base rate case.

In September 2009, the KPSC approved the deferral of $44 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 $24 million of costs associated with high winds from the remnants of Hurricane Ike in September 2008. LG&E 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, LG&E 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.

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

	December 31, 2010	
	Borrowed (a)	Letters of Credit Issued
Syndicated Credit Facility (b) (c) (d)	$ 163	$ -

(a) Amounts borrowed are recorded as "Short-term debt" on the Balance Sheets.

(b) In October 2011, LG&E amended its credit facility. The amendments include extending the expiration dates from December 2014 to October 2016. Under this credit facility, LG&E continues to have the ability to make cash borrowings and request the lenders to issue letters of credit.

(c) In June 2011, this facility was amended such that the fees and the spreads to benchmark interest rates for borrowings depend upon LG&E's senior secured long-term debt rating rather than the senior unsecured long-term debt rating. The facility contains a financial covenant requiring LG&E's debt to total capitalization not to exceed 70%, as calculated in accordance with the facility, and other customary covenants. Additionally, subject to certain conditions, LG&E may request that the facility's capacity be increased by up to $100 million.

(d) The borrowing outstanding at December 31, 2010 bore interest at 2.27%. Such borrowing was repaid in January 2011 with proceeds received from the remarketing of certain tax-exempt bonds that were held by LG&E at December 31, 2010.

In February 2012, LG&E 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 LG&E's Syndicated Credit Facility.

See Note 12 for discussion of intercompany borrowings.

Long-term Debt

	2011 (a)	2010
Senior Secured/First Mortgage Bonds (b)	$ 535	$ 535
Pollution Control Bonds (Collateral Series), due 2023-2037 (c)	574	574
Fair value adjustments from purchase accounting (d)	6	7
Unamortized discount	(3)	(4)
Total Long-term Debt	$ 1,112	$ 1,112

(a) Aggregate maturities of long-term debt are zero for each of 2012 through 2014; 2015, $250; 2016, $0; and $859 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.

LG&E's first mortgage bonds are secured by the lien of the LG&E 2010 Mortgage Indenture, which creates a lien, subject to certain exceptions and exclusions, on substantially all of LG&E'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 and the storage and distribution of natural gas. The aggregate carrying value of the property subject to the lien was $2.6 billion and $2.5 billion at December 31, 2011 and December 31, 2010.

The LG&E 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, LG&E 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, LG&E 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 LG&E 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 LG&E. The related revenue bond documents allow LG&E 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 LG&E that were in a term rate mode totaled $294 million. The weighted average rate on these bonds was 3.37%. At December 31, 2010, the amounts that were in a term rate mode totaled $156 million. The weighted average rate on these bonds was 5.22%.

At December 31, 2011, the aggregate tax-exempt revenue bonds issued on behalf of LG&E that were in a variable rate mode totaled $280 million. The weighted average rate on these bonds was 0.33%. At December 31, 2010, the amounts that were in a variable rate mode totaled $418 million. The weighted average rate on these bonds was 0.55%.

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, $135 million are in the form of insured auction rate securities, wherein interest rates are reset either weekly or 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 LG&E 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 LG&E to convert the bonds to other interest rate modes.

Certain variable rate tax-exempt revenue bonds totaling $120 million at December 31, 2011, are subject to tender for purchase by LG&E at the option of the holder and to mandatory tender for purchase by LG&E upon the occurrence of certain events. At December 31, 2010, LG&E held $163 million of such bonds, which were issued on its behalf by Louisville/Jefferson County, Kentucky and are reflected as "Short-term investments" on the Balance Sheet. In January 2011, the entire $163 million of bonds were remarketed to unaffiliated investors in a term rate mode, bearing interest at 1.90% into 2012. The proceeds from the remarketing were used to repay the borrowing under LG&E's syndicated credit facility, which is discussed above in "Credit Arrangements and Short-term Debt."

(d) Reflects adjustments made to record LG&E's long-term debt at fair value at the time of acquisition of LKE in 2010.

Distributions, Capital Contributions and Related Restrictions

LG&E 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. LG&E 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. However, Orders from the KPSC require LG&E to obtain prior regulatory consent or approval before loaning funds to PPL. At December 31, 2011, the net restricted assets of LG&E were approximately $1.7 billion.

During the year ended December 31, 2011, LG&E paid dividends of $83 million to its parent, LKE. No capital contributions were received from LKE during this period.

In February 2012, LG&E 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 LG&E by $809 million. LG&E does not anticipate changing its dividend practices.

6. Acquisitions, Development and Divestitures

LG&E 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, LG&E and KU 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, LG&E and KU will jointly acquire the Bluegrass CTs as tenants in common, with LG&E as owner of a 69% undivided interest, and KU as owner of a 31% 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, LG&E and KU 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, LG&E and KU 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, LG&E 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, LG&E issued debt totaling $531 million. The majority of these proceeds, together with a borrowing by LG&E under its available credit facilities, were 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 $1,702 million for LG&E. 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	$	503
Investments		1
PP&E		2,935
Other intangibles (current and noncurrent)		226
Regulatory and other noncurrent assets		416
Current liabilities, excluding current portion of long-term debt		(420)
PPL affiliate indebtedness		(485)
Long-term debt (current and noncurrent)		(580)
Other noncurrent liabilities		(1,283)
Net identifiable assets acquired		1,313
Goodwill		389
Net assets acquired and beginning equity balance on November 1, 2010	$	1,702

Goodwill represents value paid for the rate regulated businesses of LG&E, 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. LG&E'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 LG&E's assets and liabilities that contributed to goodwill are as follows:

The pollution control bonds, excluding the reacquired bonds, had a fair value adjustment of $7 million for LG&E. 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. LG&E's investment in OVEC was not significant and the power purchase agreement was valued at $87 million for LG&E. 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.

- LG&E recorded an emission allowance intangible asset and a regulatory liability as the result of adjusting the fair value of the emission allowances at LG&E. The emission allowance intangible of $8 million at LG&E 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. LG&E 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 LG&E for $124 million as well as a non-current liability of $11 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 LG&E, 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 $2 million in the liability balances of LG&E 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, LG&E 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. LG&E's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

LG&E also considered whether a separate fair value should be assigned to LG&E's rights to operate within its various electric and natural gas 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

LG&E and KU 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, LG&E and KU entered into an 18-year lease of the turbines. LG&E and KU 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 LG&E and KU 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, LG&E and KU 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 LG&E and KU. The maximum aggregate amount at December 31, 2011 that could be required to be paid by LG&E is $2 million and by KU is $4 million. LKE has guaranteed the payment of these potential default payments of LG&E and KU.

Other Leases

LG&E has entered into various agreements for the lease of office space, vehicles, land, gas storage 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
$ 7	$ 1	$ 5

Total future minimum rental payments for all operating leases are estimated to be:

2012	$ 5
2013	5
2014	4
2015	3
2016	1
Thereafter	1
Total	$ 19

9. Retirement and Postemployment Benefits

Defined Benefits

LG&E sponsors the Louisville Gas and Electric Company Bargaining Employees' Retirement Plan. In addition to the plan it sponsors, LG&E is allocated a portion of the funded status and costs of certain defined benefit plans sponsored by LKE based on its participation in those plans, which management believes are reasonable. The actuarially determined obligations of current active employees and retired employees are used as a basis to allocate total plan activity, including active and retiree costs and obligations. LG&E's allocated share of the funded status of the pension plans resulted in a liability of $53 million and $69 million at December 31, 2011 and 2010. LG&E's allocated share of other postretirement benefits was a liability of $87 million and $85 million at December 31, 2011 and 2010.

The defined benefit pension plans of LKE and its subsidiaries, including LG&E, 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 following table provides the components of net periodic benefit cost for LG&E's pension benefit plan 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	
	Successor	
	2011	2010
Net periodic defined benefit costs (credits):		
Service cost	$ 2	$ -
Interest cost	14	2
Expected return on plan assets	(18)	(3)
Amortization of:		
Prior service cost	2	1
Actuarial loss	11	2
Net periodic defined benefit costs	$ 11	$ 2
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets - Gross:		
Current year net (gain) loss	$ 15	$ (5)
Current year prior service cost	9	-
Amortization of:		
Prior service cost	(2)	-
Actuarial (loss)	(11)	(2)
Total recognized in regulatory assets	11	(7)
Total recognized in net periodic benefit costs and regulatory assets	$ 22	$ (5)

	Pension Benefits Predecessor 2010
Net periodic defined benefit costs (credits):	
Service cost	$ 1
Interest cost	12
Expected return on plan assets	(13)
Amortization of:	
Prior service cost	2
Actuarial loss	6
Net periodic defined benefit costs	$ 8
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets - Gross:	
Current year net (gain) loss	$ 18
Amortization of:	
Prior service cost	(2)
Actuarial (loss)	(6)
Total recognized in regulatory assets	10
Total recognized in net periodic benefit costs and regulatory assets	$ 18

The estimated amounts to be amortized from regulatory assets into net periodic benefit costs for LG&E in 2012 are as follows.

	Pension Benefits
Prior service cost	$ 2
Actuarial loss	10
Total	$ 12

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
$ 16	$ 3	$ 12

Other Postretirement Benefits (a)

Successor		Predecessor
2011	2010	2010
$ 5	$ 1	$ 4

(a) Includes costs for the specific plans it sponsors and allocated costs of defined benefit plans sponsored by LKE, based on its participation in those plans.

The following table provides defined benefit costs allocated from LKE.

Pension Benefits		
Successor		Predecessor
2011	2010	2010
$ 7	$ 1	$ 6

Other Postretirement Benefits		
Successor		Predecessor
2011	2010	2010
$ 5	$ 1	$ 4

The following table provides the weighted-average assumptions used in the valuation of the benefit obligations at December 31, 2011 and 2010, for the Successor, and at October 31, 2010, for the Predecessor.

	Pension Benefits		
	Successor		Predecessor
	2011	2010	2010
Discount rate	5.00%	5.39%	5.32%
Rate of compensation increase	N/A	N/A	N/A

The following table provides the weighted-average assumptions used to determine the net periodic benefit costs 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		
	Successor		Predecessor
	2011	2010	2010
Discount rate	5.39%	5.28%	6.08%
Rate of compensation increase	N/A	N/A	N/A
Expected return on plan assets (a)	7.25%	7.25%	7.75%

(a) The expected long-term rates of return for LG&E's pension and other postretirement benefits have been developed using a best-estimate of expected returns, volatilities and correlations for each asset class. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes. LG&E management corroborates these rates with expected long-term rates of return calculated by its independent actuary, who uses a building block approach that begins with a risk-free rate of return with factors being added such as inflation, duration, credit spreads and equity risk. Each plan's specific asset allocation is also considered in developing a reasonable return assumption.

The funded status of the LG&E plan was as follows 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			
	Successor			
	2011		2010	
Change in Benefit Obligation				
Benefit Obligation, beginning of period	$	274	$	276
Service cost		2		-
Interest cost		14		2
Plan amendments		9		-
Actuarial loss		14		(2)
Gross benefits paid		(15)		(2)
Benefit Obligation, end of period		298		274
Change in Plan Assets				
Plan assets at fair value, beginning of period		217		214
Actual return on plan assets		16		6
Employer contributions		38		-
Actual expenses paid		(15)		-
Gross benefits paid		-		(3)
Plan assets at fair value, end of period		256		217
Funded Status, end of period	$	(42)	$	(57)
Amounts recognized in the Balance Sheets consist of:				
Noncurrent liability	$	(42)	$	(57)
Net amount recognized, end of period	$	(42)	$	(57)
Amounts recognized in regulatory assets (pre-tax) consists of:				
Prior service cost	$	20	$	13
Net actuarial loss		115		111
Total	$	135	$	124
Total accumulated benefit obligation for defined benefit pension plan	$	292	$	274

	Pension Benefits Predecessor 2010
Change in Benefit Obligation	
Benefit Obligation, beginning of period	$ 251
Service cost	2
Interest cost	12
Plan amendments	-
Actuarial loss	24
Gross benefits paid	(13)
Benefit Obligation, end of period	276
Change in Plan Assets	
Plan assets at fair value, beginning of period	196
Actual return on plan assets	19
Employer contributions	12
Actual expenses paid	-
Gross benefits paid	(13)
Plan assets at fair value, end of period	214
Funded Status, end of period	$ (62)
Amounts recognized in the Balance Sheets consist of:	
Noncurrent liability	$ (62)
Net amount recognized, end of period	$ (62)
Amounts recognized in regulatory assets (pre-tax) consists of:	
Prior service cost	$ 14
Net actuarial loss	118
Total	$ 132
Total accumulated benefit obligation for defined benefit pension plan	$ 273

LG&E's pension plan had projected and accumulated benefit obligations in excess of plan assets at December 31, 2011 and 2010.

Plan Assets - Pension Plans

The investment policies of the Louisville Gas and Electric Company Bargaining Employees' Retirement Plan trust (LG&E pension trust) outline allowable investments and define the responsibilities of the EBPB and the external investment managers. The only prohibited investments are investments in debt or equity securities issued by PPL and its subsidiaries or PPL's pension plan consultant. Derivative instruments may be utilized as a cost-effective means to mitigate risk and match the duration of investments to projected obligations. The investment policies are reviewed annually by PPL's Board of Directors.

The EBPB created a risk management framework around the trust assets and pension liabilities. This framework considers the trust assets as being composed of three sub-portfolios: the growth, immunizing and liquidity portfolios. The growth portfolio is comprised of investments that generate a return at a reasonable risk, including equity securities, certain debt securities and alternative investments. The immunizing portfolio consists of debt securities and derivative positions that will typically have long durations. The immunizing portfolio is designed to offset a portion of the change in the pension liabilities due to changes in interest rates. The liquidity portfolio consists primarily of cash and cash equivalents.

Target allocation ranges have been developed for each portfolio based on input from external consultants with a goal of limiting funded status volatility. The EBPB monitors the investments in each portfolio, and seeks to obtain a target portfolio that emphasizes reduction of risk of loss from market volatility. In pursuing that goal, the EBPB establishes revised guidelines from time to time.

The asset allocation for the trusts and the target allocation by portfolio, at December 31 are as follows.

LG&E Pension Trust

	Percentage of Trust Assets	Target Range	Target Asset Allocation
	2011	2011	2011
Growth Portfolio	**51%**	**45 - 60%**	**59%**
Equity securities	33%		
Debt securities (a)	18%		
Immunizing Portfolio	**36%**	**35 - 55%**	**38%**
Debt securities (a) (b)	36%		
Liquidity Portfolio (b)	**13%**	**0 - 9%**	**3%**
Total	100%		100%

(a) Includes commingled debt funds, which LG&E treats as debt securities for asset allocation purposes.
(b) The asset allocation for this portfolio is not within the established target range due to the transition of assets at the end of 2011 in anticipation of a transfer into the PPL Services Corporation Master Trust in January 2012.

Prior to the fourth quarter of 2011, the LG&E pension trust was managed using a different investment policy.

As of December 31, 2010, the asset allocation was as follows.

	Percentage of Trust Assets	Target Range
	2010	**2010**
Asset Class		
Equity securities	57%	45 - 75%
Debt securities (a)	43%	30 - 50%
Other	0%	0 - 10%
Total	100%	

(a) Includes commingled debt funds.

The fair value of net assets in the LG&E pension trust by asset class and level within the fair value hierarchy was:

	December 31, 2011			
	Total	Level 1	Level 2	Level 3
LG&E Pension Trust				
Cash and cash equivalents	$ 34	$ 34	$ -	$ -
Equity securities				
U.S.:				
Large-cap	55	-	55	-
Commingled debt	18	-	18	-
International	29	-	29	-
Debt securities:				
U.S. Treasury	27	27	-	-
Corporate	93	-	93	-
Derivatives:				
Total return swaps	1	-	1	-
Total LG&E pension trust assets	$ 257	$ 61	$ 196	$ -

	December 31, 2010			
	Total	Level 1	Level 2	Level 3
LG&E Pension Trust				
Cash and cash equivalents	$ 1	$ 1	$ -	$ -
Equity securities				
U.S.:				
Large-cap	77	-	77	-
Small/Mid-cap	18	-	18	-
Commingled debt	93	-	93	-
International	28	-	28	-
Total LG&E pension trust assets	$ 217	$ 1	$ 216	$ -

The fair value measurements of cash and cash equivalents are based on the amounts on deposit.

The market approach is used to measure fair value of equity securities. The fair value measurements of equity securities (excluding commingled funds), which are generally classified as Level 1, are based on quoted prices in active markets. These securities represent actively and passively managed investments that are managed against various equity indices.

Investments in commingled funds are classified as Level 2 and categorized as equity securities. The fair value measurements are based on firm quotes of net asset values per share, which are not considered obtained from a quoted price in an active market. For the PPL Services Corporation Master Trust for 2011 and 2010 and the

LG&E pension trust for 2011, these securities represent investments that are measured against the Russell 1000 Growth Index, the Russell 3000 Index and the MSCI EAFE Index. For the LG&E pension trust during 2010, these securities represent passively and actively managed investments in equity funds managed against the S&P 500 Index, the Russell 2500 Growth & Value Indexes and the MSCI EAFE Index.

The fair value measurements of debt securities are generally based on evaluated prices that reflect observable market information, such as actual trade information for identical securities or for similar securities, adjusted for observable differences. Debt securities are generally measured using a market approach, including the use of matrix pricing. Common inputs include reported trades; broker/dealer bid/ask prices, benchmark securities and credit valuation adjustments. When necessary, the fair value of debt securities is measured using the income approach, which incorporates similar observable inputs as well as benchmark yields, credit valuation adjustments, reference data from market research publications, monthly payment data, collateral performance and new issue data. During 2010 and the first ten months of 2011 for the LG&E pension trust, debt securities within commingled trusts were managed against the Barclays Aggregated Bond Index and the Barclays U.S. Government/Credit Long Index. During the last two months of 2011, the debt securities for the LG&E pension trust were transitioned to debt securities similar to those within the PPL Services Corporation Master Trust. The debt securities, excluding those in commingled funds, held by the PPL Services Corporation Master Trust at December 31, 2011 have a weighted-average coupon of 3.96% and a weighted-average maturity of 25 years.

The fair value measurements of derivative instruments 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. These securities represent investments in interest rate swaps. Interest rate swaps are valued based on the swap details such as: swap curves, notional amount, index and term of index, reset frequency and payer/receiver credit ratings.

There were no assets classified as Level 3.

Expected Cash Flows - Defined Benefit Plan

LG&E's defined benefit plan has the option to utilize available prior year credit balances to meet current and future contribution requirements. However, LG&E contributed $13 million to its pension plan in January 2012.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid by the separate plan trust.

	Pension
2012	$ 15
2013	15
2014	15
2015	15
2016	15
2017-2021	90

Contributions

LG&E made contributions to its defined benefit pension plan of $38 million and $12 million in 2011 and 2010. LG&E also made contributions to the defined benefit pension plan in which is participates of $26 million and $8 million in 2011 and 2010. In 2012, LG&E made contributions of $13 million to its defined benefit pension plan.

LG&E 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. LG&E funded this plan $6 million and $7 million in 2011 and 2010. Continuation of this past practice would cause LG&E to contribute $7 million to the other postretirement benefit plan in 2012.

Savings Plans

Substantially all of LG&E'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
$ 5	$ 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, LG&E 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	37.00%	$ 64	$ 4	$ 1
E.W. Brown Units 6-7	38.00%	39	3	-
Trimble County Units 5-6	29.00%	31	1	-
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00%	44	2	5
Trimble County Unit 1	75.00%	297	19	11
Trimble County Unit 2	14.25%	190	7	7
December 31, 2010				
Generating Plants				
Trimble County Units 7-10	37.00%	$ 63	$ 1	$ 1
E.W. Brown Units 6-7	38.00%	39	2	1
Trimble County Units 5-6	29.00%	26	-	2
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00%	44	-	4
Trimble County Unit 1	75.00%	288	9	17
Trimble County Unit 2	14.25%	2	-	187

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

LG&E 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 approval in August 2011. Pursuant to the OVEC power purchase contract, LG&E 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. LG&E's proportionate share of OVEC's outstanding debt was $81 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	$	20
2013		21
2014		21
2015		21
2016		22
Thereafter		595
	$	700

In addition, LG&E 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
$ 22	$ 4	$ 17

LG&E 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. LG&E also enters into contracts for other coal related consumables, coal transportation and fleeting services, which expire at different time periods through 2018. LG&E also has transportation contracts for natural gas that extend through 2018.

Legal Matters

LG&E is involved in legal proceedings, claims and litigation in the ordinary course of business. LG&E cannot predict the outcome of such matters, or whether such matters may result in material liabilities, unless otherwise noted.

TC2 Construction

In June 2006, LG&E and KU, 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. LG&E 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, LG&E likely will be faced with significant new recordkeeping and reporting requirements. Also, LG&E 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. LG&E will continue to evaluate the provisions of the Dodd-Frank Act. At this time, LG&E 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 LG&E to make wholesale sales of electric power and related products at market-based rates. In those orders, the FERC directed LG&E 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 LG&E. Also, in June 2011, PPL filed its market-based rate update for the Southeast region, including LG&E. In June 2011, the FERC issued an Order approving LG&E'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, LG&E 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.

LG&E 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. LG&E 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 LG&E, 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, LG&E 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.

Air

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, LG&E'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 $1.6 billion for LG&E (which includes $100 million associated with currently approved ECR plans through 2013 to achieve emissions reductions and manage coal combustion residuals, $1.4 billion 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 $100 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 LG&E 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 LG&E'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 LG&E coal-fired generating plants, the stay of the CSAPR will initially only impact the unit dispatch order. With the return of the CAIR and LG&E'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. LG&E'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, LG&E'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. LG&E 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 upgraded or new sulfur dioxide scrubbers at the Mill Creek plant and retirement of the Cane Run plant 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, LG&E 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 $1.6 billion noted under "Air" above. LG&E has also announced the anticipated retirement of coal-fired generating units at the Cane Run plant 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, LG&E is currently assessing whether changes in the final rule warrant revision of its approved compliance plans. LG&E is continuing to conduct in-depth reviews of the MATS.

Regional Haze and Visibility

LG&E submitted analyses of the visibility impacts of its Best Available Retrofit Technology (BART) eligible sources to the Kentucky Division for Air Quality (KDAQ). Only LG&E's Mill Creek plant was determined to have a significant regional haze impact. The KDAQ has submitted a regional haze state implementation plan (SIP) to the EPA which requires the Mill Creek plant to reduce its sulfuric acid mist emissions from Units 3 and 4. After approval of the SIP by the EPA and revision of the Mill Creek plant's Title V air permit, LG&E intends to install sorbent injection controls at the plant to reduce sulfuric acid mist emissions. 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 LG&E 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, LG&E received information requests for its Mill Creek and Trimble County plants, but has received no further communications from the EPA since providing their responses. LG&E cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any.

If LG&E is found to have violated NSR regulations, LG&E 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 LG&E 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, LG&E 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 four of LG&E’s affiliates but excluding LG&E, 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. LG&E cannot predict the outcome of this litigation or estimate a range of reasonably possible losses, if any.

In 2011, LG&E and its jointly owned power plants emitted approximately 21 million tons of carbon dioxide compared with 19 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, LG&E 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. LG&E 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 LG&E 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.

LG&E 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. LG&E 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 LG&E’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. LG&E 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. LG&E 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 LG&E 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. LG&E 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. LG&E 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, LG&E 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. LG&E 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

LG&E is remediating or has completed the remediation of several sites that were not addressed under a regulatory program such as Superfund, but for which LG&E 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 LG&E. There are additional sites, formerly owned or operated by LG&E predecessors or affiliates, for which LG&E 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 LG&E currently lacks information, the costs of remediation and other liabilities could be substantial. LG&E also could incur other non-remediation costs at sites included in current consent orders or other contaminated sites which could be significant. LG&E 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 LG&E to take more extensive assessment and remedial actions at former coal gas manufacturing facilities. LG&E cannot estimate a range of reasonably possible losses, if any, related to these matters.

From time to time, LG&E 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 LG&E'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 LG&E'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 LG&E.

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. LG&E 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. LG&E 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, LG&E 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, LG&E 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 LG&E'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, LG&E is obligated to pay its share of the excess. The maximum exposure of this obligation cannot be determined at this time.

LG&E 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

LG&E and subsidiaries of LKE and PPL engage in related party transactions. Transactions between LG&E and LKE subsidiaries are eliminated upon consolidation of LKE. Transactions between LG&E 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 regulations.

Wholesale Sales and Purchases

LG&E and KU 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 LG&E 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
$ 190	$ 32	$ 200

In addition, LG&E and KU provide services to each other and to LKS. Billings between LG&E and KU 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 LG&E are reimbursed through LKS.

Intercompany Borrowings

In November 2010, a PPL Energy Supply subsidiary held term notes with LG&E. 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 4.33% and 6.48%. Interest on these notes is included in "Interest Expense with Affiliates." When balances were outstanding, interest on these notes was $1 million for 2010.

LG&E participates in an intercompany money pool agreement whereby LKE and/or KU make available to LG&E 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, $12 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 KU was not significant for 2011 or 2010.

Prior to PPL's acquisition of LKE in November 2010, LG&E had long-term loans from its former E.ON AG affiliates. During 2010, LG&E incurred interest expense on these debt arrangements of $22 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 7 for a discussion regarding capital transactions by LG&E. 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			
Net derivative gains (losses)	$ -	$ -	$ 19
Miscellaneous	-	-	1
Total Other Income	-	-	20
Other Expense			
Charitable contributions	1	-	2
Miscellaneous	1	3	1
Total Other Expense	2	3	3
Other Income (Expense) - net	$ (2)	$ (3)	$ 17

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). LG&E 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	$ 25	$ 25	$ -	$ -
Restricted cash and cash equivalents (a)	29	29	-	-
Total assets	$ 54	$ 54	$ -	$ -
Liabilities				
Price risk management liabilities:				
Interest rate swaps (b)	$ 60	$ -	$ 60	$ -

	December 31, 2010			
	Total	Level 1	Level 2	Level 3
Assets				
Cash and cash equivalents	$ 2	$ 2	$ -	$ -
Short-term investments - municipal debt securities	163	163	-	-
Restricted cash and cash equivalents (a)	22	22	-	-
Total assets	$ 187	$ 187	$ -	$ -
Liabilities				
Price risk management liabilities:				
Energy commodities (c)	$ 2	$ -	$ 2	$ -
Interest rate swaps (b)	34	-	34	-
Total liabilities	$ 36	$ -	$ 36	$ -

(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.
(b) Current portion is included in "Other current liabilities" on the Balance Sheets. The long-term portion is included in "Price risk management liabilities" on the Balance Sheets.
(c) Included in "Other current liabilities" on the Balance Sheets.

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, LG&E 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.

Price Risk Management Assets/Liabilities - Interest Rate Swaps

To manage its interest rate risk, LG&E generally uses interest rate contracts such as forward-starting swaps, floating-to-fixed swaps and fixed-to-floating swaps. LG&E uses an income approach to measure the fair value of these contracts, utilizing readily observable inputs, such as forward interest rates (e.g., LIBOR and government security rates) as well as inputs that may not be observable, such as credit valuation adjustments. In certain cases, LG&E cannot practicably obtain market information to value credit risk and therefore rely on its own models. These models use projected probabilities of default based on historical observances. When the credit valuation adjustment is significant to the overall valuation, the contracts are classified as Level 3.

Financial Instruments Not Recorded at Fair Value

The carrying values and estimated fair values of LG&E's non-trading financial instruments follow:

	December 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 1,112	$ 1,164	$ 1,112	$ 1,069

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. The carrying value of short-term investments approximates fair value due to the liquid nature and short-term duration of these instruments.

Credit Concentration Associated with Financial Instruments

LG&E 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 LG&E to manage credit risk, including master netting arrangements and collateral requirements.

At December 31, 2011, LG&E's credit exposure was not significant.

15. Derivative Instruments and Hedging Activities

Risk Management Objectives

LG&E 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 LG&E's parent, LKE, (acquired in November 2010) under the risk management policy.

Market Risk

Market risk is the potential loss LG&E may incur as a result of price changes associated with a particular financial or commodity instrument. LG&E utilizes forward contracts and swaps as part of risk management strategies, to minimize unanticipated fluctuations in earnings caused by changes in commodity prices and interest rates. All derivatives are recognized on the Balance Sheets at their fair value, unless they qualify for NPNS.

By definition, the regulatory environment for LG&E significantly mitigates market risk. LG&E's rates are set to permit the recovery of prudently incurred costs, including certain mechanisms for fuel, gas supply and environmental expenses. These mechanisms generally provide for timely recovery of market price and volumetric fluctuations associated with these expenses. LG&E primarily utilized forward financial transactions to manage price risk associated with expected economic generation capacity in excess of expected load requirements.

LG&E also utilizes over-the-counter interest rate swaps to limit exposure to market fluctuations on interest expense.

Credit Risk

Credit risk is the potential loss LG&E may incur due to a counterparty's non-performance, including defaults on payments and energy commodity deliveries.

LG&E is exposed to credit risk from interest rate derivatives with financial institutions.

LG&E's credit risk stems from its commodity derivatives for contracts for energy sales and purchases. In the event a supplier of LG&E defaults on its obligation, LG&E would be required to seek replacement power or replacement fuel in the market. In general, incremental costs incurred by LG&E would be recoverable from customers in future rates.

LG&E 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. LG&E 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

LG&E 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.

LG&E had no obligation to return cash collateral under master netting arrangements at December 31, 2011 and December 31, 2010.

LG&E had posted cash collateral under master netting arrangements of $29 million at December 31, 2011 and $19 million at December 31, 2010.

Commodity Price Risk (Non-trading)

LG&E 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 LG&E at December 31, 2010 was not significant. There is no economic position at December 31, 2011. Unrealized gains (losses) for economic activity for LG&E in 2011 and 2010 were not significant.

Interest Rate Risk

LG&E has issued debt to finance its operations, which exposes it to interest rate risk. LG&E utilizes various financial derivative instruments to adjust the mix of fixed and floating interest rates in its debt portfolio, adjust the duration of its debt portfolio and lock in benchmark interest rates in anticipation of future financing, when appropriate. Risk limits under the risk management program are designed to balance risk exposure to volatility in interest expense and changes in the fair value of LG&E's debt portfolio due to changes in benchmark interest rates.

Economic Activity

LG&E enters into interest rate swap contracts that economically hedge interest payments on variable rate debt. Because realized gains and losses from the swaps, including a terminated swap contract, are recoverable through regulated rates, any subsequent changes in fair value of these derivatives are included in regulatory assets or liabilities until they are realized as interest expense. Realized gains and losses are recognized in "Interest Expense" on the Statements of Income when the hedged transaction occurs. At December 31, 2011, LG&E held contracts with aggregate notional amounts of $179 million that range in maturity through 2033. The fair value of these contracts was recorded as liabilities of $60 million and $34 million at December 31, 2011 and 2010, with equal offsetting amounts recorded as regulatory assets.

Prior to the third quarter of 2010, LG&E accounted for these contracts as cash flow hedges and reclassified amounts previously recorded in AOCI to earnings in the same period during which the forecasted transaction affected earnings.

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, except for the changes in fair value of LG&E's interest rate swaps, which beginning in the third quarter of 2010, have been recognized as regulatory assets. See Note 4 for amounts recorded in regulatory assets at December 31, 2011 and December 31, 2010.

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 Decembere 31, 2011 and 2010. The following table presents the fair value and location of derivative instruments not designated as hedging instruments recorded on the Balance Sheets:

	December 31, 2011		December 31, 2010	
	Derivatives not designated as hedging instruments		Derivatives not designated as hedging instruments	
	Assets	Liabilities	Assets	Liabilities
Current:				
Other Current Assets/Liabilities (a):				
Interest rate swaps	$ -	$ 5	$ -	$ 2
Commodity contracts	-	-	-	2
Total current	-	5	-	4
Noncurrent:				
Price Risk Management Assets/Liabilities (a):				
Interest rate swaps	-	55	-	32
Total noncurrent	-	55	-	32
Total derivatives	$ -	$ 60	$ -	$ 36

(a) Represents the location on the Balance Sheet.

The following tables present the pre-tax effect of derivative instruments recognized in income or regulatory assets for the periods ended December 31, 2011 and 2010, for the Successor and Predecessor.

		Successor	
Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Year Ended December 31, 2011	Two Months Ended December 31, 2010
Interest rate swaps	Interest expense	$ (8)	$ (1)
Commodity contracts	Operating revenues - retail and wholesale	(1)	(2)
	Total	$ (9)	$ (3)

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Predecessor Ten Months Ended October 31, 2010
Interest rate swaps	Interest expense	$ (7)
Commodity contracts	Operating revenues - retail and wholesale	3
	Total	$ (4)

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	December 31, 2011	December 31, 2010
Interest rate swaps	Regulatory assets	$ (26)	$ (43)

Credit Risk-Related Contingent Features

Certain of LG&E's derivative contracts contain credit risk-related contingent provisions which, when in a net liability position, would permit the counterparties to require the transfer of additional collateral upon a decrease in the credit ratings of LG&E. Most of these provisions would require LG&E to transfer additional collateral or permit the counterparty to terminate the contract if the applicable credit rating were to fall below investment grade. Some of these provisions also would 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 the applicable credit rating were to fall below investment grade (i.e., below BBB- for S&P or Fitch, 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 LG&E on derivative instruments in net liability positions.

Additionally, certain of LG&E's derivative contracts contain credit risk-related contingent provisions that require LG&E to provide "adequate assurance" of performance if the other party has reasonable grounds for insecurity regarding LG&E'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. This would typically involve negotiations among the parties. However, amounts disclosed below represent assumed immediate payment or immediate and ongoing full collateralization for derivative instruments in net liability positions with "adequate assurance" provisions.

At December 31, 2011, the effect of a decrease in credit ratings below investment grade on derivative contracts that contain credit contingent features and were in a net liability position is summarized as follows:

Aggregate fair value of derivative instruments in a net liability position with credit risk-related contingent provisions	$	39
Aggregate fair value of collateral posted on these derivative instruments		29
Aggregate fair value of additional collateral requirements in the event of a credit downgrade below investment grade (a)		10

(a) Includes the effect of net receivables and payables already recorded on the Balance Sheet.

16. Goodwill and Other Intangible Assets

Goodwill

As a result of the November 1, 2010 acquisition by PPL, LG&E recognized $389 million of goodwill. The allocation of goodwill was based on LG&E'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)	$ 124	$ 46	$ 124	$ 6
Land and transmission rights (b)	6	1	6	-
Emission allowances (c)	2	-	7	-
OVEC power purchase agreement (d)	87	6	87	1
Total subject to amortization	$ 219	$ 53	$ 224	$ 7

(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 $5 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 no regulatory offset	$ 1	$ -
Intangible assets with regulatory offset	45	7
Total	$ 46	$ 7

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	$ 22	$ 25	$ 23	$ 24	$ 14

17. Asset Retirement Obligations

LG&E's AROs are primarily related to the final retirement of assets associated with generating units, natural gas mains and wells. LG&E'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 LG&E 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	$	31
Accretion expense		2
Changes in estimated cash flow or settlement date		30
Obligations settled		(1)
ARO at October 31, 2010, Predecessor		62
Purchase accounting		(13)
ARO at December 31, 2010, Successor		49
Accretion expense		3
Obligations incurred		2
Changes in estimated cash flow or settlement date		4
Obligations settled		(1)
ARO at December 31, 2011, Successor	$	57

The classification of AROs on the Balance Sheets was as follows.

	December 31, 2011		December 31, 2010	
Current portion (a)	$	2	$	-
Long-term portion (b)		55		49
Total	$	57	$	49

(a) Included in "Other current liabilities."
(b) Included in "Asset retirement obligations."

18. Available-for-Sale Securities

LG&E classifies certain short-term investments as available-for-sale. Available-for-sale securities are carried on the Balance Sheet at fair value. Unrealized gains and losses on these securities are reported, net of tax, in OCI or are recognized currently in earnings when a decline in fair value is determined to be other-than-temporary. The specific identification method is used to calculate realized gains and losses.

LG&E had no available-for-sale securities at December 31, 2011. At December 31, 2010, LG&E held $163 million in municipal debt securities classified as available-for-sale securities at both amortized cost and fair value.

There were no securities with credit losses at December 31, 2011 and 2010.

Short-term Investments

At December 31, 2010, LG&E held $163 million aggregate principal amount of tax-exempt revenue bonds issued by Louisville/Jefferson County, Kentucky on behalf of LG&E that were purchased from the remarketing agent in 2008. At December 31, 2010, these investments were reflected in "Short-term investments" on the Balance Sheet. In 2011, LG&E received $163 million for its investments in these bonds when they were remarketed to unaffiliated investors. No realized or unrealized gains (losses) were recorded on these securities, as the difference between carrying value and fair value was not significant.

19. New Accounting Guidance Pending Adoption

Fair Value Measurements

Effective January 1, 2012, LG&E 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 LG&E.

Testing Goodwill for Impairment

Effective January 1, 2012, LG&E 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 LG&E.

Improving Disclosures about Offsetting Balance Sheet Items

Effective January 1, 2013, LG&E 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 LG&E.

20. 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	$ 20	$ 53
Interest on borrowed money	30	11
Interest to affiliated companies on borrowed money	-	29
Other cash paid for interest	9	10

21. Notes to Statement of Income for the Year

See page 115, line 6, column (g). Electric Utility Depreciation Expense includes $9 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 6, column (i). Gas Utility Depreciation Expense $4 million applicable to Common Utility Plant apportioned to Gas Operations.

See page 115, line 8, column (g). Electric Utility Amortization and Depletion of Utility Plant includes $6 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 8, column (i). Gas Utility Amortization and Depletion of Utility Plant includes $2 million applicable to Common Utility Plant apportioned to Gas Operations.

Louisville Gas and Electric Company
Case No. 2012-00222
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 LG&E's latest depreciation study is already on file with the Commission in LG&E's consolidated depreciation case, Case No. 2007-00564, *In the Matter of: Application of Louisville Gas and Electric Company to File Depreciation Study*, and rate case, Case No. 2008-00252, *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Base Rates*, and is incorporated by reference herein. As part of this current rate case application, LG&E is filing a new depreciation study, as referenced in the testimony and exhibits of John J. Spanos.

Louisville Gas and Electric Company
Case No. 2012-00222
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

Louisville Gas and Electric Company
Case No. 2012-00222
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.

NOT A NEW ISSUE **BOOK-ENTRY ONLY**

On April 26, 2007, 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 offered 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 not 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 expiration of the current Long Term Rate Period and the change to a new Long Term Rate Period, as more fully described in this Reoffering Circular, Bond Counsel will deliver its opinion to the effect that such change (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 the information under the caption "Tax Treatment" in this Reoffering Circular.

$35,200,000
Louisville/Jefferson County
Metro Government, Kentucky
Environmental Facilities Revenue Refunding Bonds, 2007 Series B
(Louisville Gas and Electric Company Project)

Due: June 1, 2033

Mandatory Purchase Date: June 1, 2017

Interest Payment Dates: June 1 and December 1

Interest Rate: 1.60%

Date of Change of Long Term Rate Period: June 1, 2012

The Louisville/Jefferson County Metro Government, Kentucky Environmental Facilities Revenue Refunding Bonds, 2007 Series B (Louisville Gas and Electric Company Project) (the "Bonds") are special and limited obligations of the Louisville/Jefferson County Metro Government, 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 Louisville Gas and Electric 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 policy or any other form of credit enhancement.** Principal of, and interest on, the Bonds are secured by the delivery to Deutsche Bank Trust Company Americas, as Trustee, of First Mortgage Bonds of

LOUISVILLE GAS AND ELECTRIC COMPANY

The Bonds were originally issued on April 26, 2007 and currently bear interest at a Long Term Rate to and including May 31, 2012. Pursuant to the Indenture under which the Bonds were issued, the Company has elected to exercise its option to change the existing Long Term Rate Period to a new Long Term Rate Period, effective as of June 1, 2012 (the "Change Date"). As a result of the expiration of the Long Term Rate Period applicable to the Bonds on May 31, 2012, the Bonds are subject to mandatory purchase on the Change Date and are being reoffered hereby. J.P. Morgan Securities LLC will serve as the Remarketing Agent for the Bonds.

The Bonds will accrue interest from the Change Date, payable on June 1 and December 1, commencing on December 1, 2012. The interest rate period, interest rate and Interest Rate Mode for the Bonds will be subject to change under certain conditions, in whole or in part, as described in this Reoffering Circular. The Bonds will be 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 will be subject to mandatory purchase at the end of each Long Term Rate Period.

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 $5,000 and integral multiples thereof. 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 more fully 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 Change 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 Dorothy O'Brien, Esq., Vice President and Deputy General Counsel, Legal and Environmental Affairs of the Company, 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 June 1, 2012.

J.P. Morgan

Dated: May 17, 2012

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, their 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 in this Reoffering Circular are subject to change without notice and neither the delivery of this Reoffering Circular nor any sale made hereunder will, 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 in this Reoffering Circular 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 which 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 such 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.

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$35,200,000
Louisville/Jefferson County
Metro Government, Kentucky
Environmental Facilities Revenue Refunding Bonds, 2007 Series B
(Louisville Gas and Electric Company Project)
Due: June 1, 2033

Introductory Statement

This Reoffering Circular, including the cover page and appendices, is provided to furnish information in connection with the reoffering by the Louisville/Jefferson County Metro Government, Kentucky (the "Issuer") of its Environmental Facilities Revenue Refunding Bonds, 2007 Series B (Louisville Gas and Electric Company Project), in the aggregate principal amount of $35,200,000 (the "Bonds") issued on April 26, 2007 pursuant to an Indenture of Trust dated as of March 1, 2007, as amended and restated by the Amended and Restated Indenture of Trust dated as of November 1, 2010 (the "Indenture") between the Issuer and Deutsche Bank Trust Company Americas, as Trustee, Paying Agent, Tender Agent and Bond Registrar (the "Trustee").

Pursuant to a Loan Agreement by and between Louisville Gas and Electric Company (the "Company") and the Issuer, dated as of March 1, 2007, as amended and restated by the Amended and Restated Loan Agreement dated as of November 1, 2010 (the "Loan Agreement"), proceeds from the sale of the Bonds 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) were assigned to the Trustee as security for the Bonds.

For the purpose of further securing the Bonds, the Company has issued and delivered to the Trustee a tranche of the Company's First Mortgage Bonds, Collateral Series 2010 (the "First Mortgage Bonds"). The principal amount, maturity date and interest rate (or method of determining interest rates) of such tranche of First Mortgage Bonds is 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 "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds" and "Summary of 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.

The First Mortgage Bonds have been issued under, and are secured by, 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 proceeds of the Bonds were applied to pay and discharge $35,200,000 outstanding principal amount of County of Jefferson, Kentucky Pollution Control Revenue Bonds, 1993 Series A (Louisville Gas and Electric Company Project), dated August 31, 1993, previously issued by the governmental predecessor of the Issuer to currently refinance certain prior pre-1986 bonds, which financed a portion of the project, consisting of certain air and water pollution control and solid waste disposal facilities (the "Project") owned by the Company.

The Company currently is an operating subsidiary of LG&E and KU Energy LLC and PPL Corporation. 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 a subsidiary of E.ON AG. See "Appendix A — Louisville Gas and Electric Company." None of LG&E and KU Energy LLC, PPL Corporation or E.ON AG has any obligation to make any payments due under the Loan Agreement or First Mortgage Bonds or any other payments of principal, interest, premium or purchase price of the Bonds.

Pursuant to the Indenture, the Company has elected to exercise its option to change the existing Long Term Rate Period for the Bonds to a new Long Term Rate Period commencing the date appearing on the cover of this Reoffering Circular. On the Mandatory Purchase Date of June 1, 2017, the Bonds may be subsequently converted to a new Interest Rate Mode or the Long Term Rate Period may be changed at its expiration to another Long Term Rate Period. **This Reoffering Circular pertains only to the Bonds during such period of time that they bear interest at the Long Term Rate established on the Change Date of June 1, 2012.**

The Bonds are secured by payments made by the Company under the Loan Agreement, and are further secured by the First Mortgage Bonds. The Bonds are not entitled to the benefits of any financial guaranty insurance policy or any other form of credit enhancement.

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 amounts payable under the First Mortgage Bonds. 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.

J.P. Morgan Securities LLC (the "Remarketing Agent") will be appointed under the Indenture to serve as Remarketing Agent for the Bonds. 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.

Brief descriptions of the Company, the Issuer, the Bonds, the First Mortgage Bonds (including the Supplemental Indenture and the First Mortgage Indenture), the Loan Agreement and the Indenture 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 change in the Long Term Rate Period. 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 in this Reoffering Circular to the documents are qualified in their entirety by reference to such documents, and references in this Reoffering Circular to the Bonds are qualified in their entirety by reference to the definitive form thereof included in the Indenture. Copies of the Loan Agreement and the Indenture will be available for inspection at the principal corporate trust office of the Trustee. The First Mortgage Indenture is available for inspection at the office of the Company in Louisville, Kentucky, and at the corporate trust office of the First Mortgage Trustee in New York, New York. Certain information relating to The Depository Trust Company ("DTC") and the book-entry-only system has been furnished by DTC. All statements in this Reoffering Circular 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. The Project consists of certain air and water pollution control and solid waste disposal facilities in connection with the Mill Creek and Cane Run Stations of the Company situated in Jefferson County, Kentucky. Major components of the Project include the acquisition, construction, installation and equipping of electrostatic precipitators, sulphur dioxide removal systems, an ash retention and disposal basin, sludge processing facilities, solid waste disposal facilities and a mechanical draft cooling tower serving generating units at the two generating stations.

The Natural Resources and Environmental Protection Cabinet (now the Energy and Environment Cabinet) of the Commonwealth of Kentucky and the Air Pollution Control District of Jefferson County, the agencies exercising jurisdiction with respect to the Project, have each previously certified that the Project as designed is in furtherance of the purpose of controlling atmospheric and water pollutants or contaminants.

The Issuer

The Issuer is a public body corporate and politic duly created and existing as a political subdivision under the Constitution and laws of the Commonwealth of Kentucky. The Issuer is authorized by Chapter 67C and Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (collectively, the "Act") to (i) change the Long Term Rate Period and reoffer the Bonds and (ii) continue to perform its obligations under the Loan Agreement and the Indenture. The Issuer, through its legislative body, the Metro Government Legislative Council, 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 OR ON BEHALF OF THE ISSUER UNDER THE LOAN AGREEMENT AND OTHER AMOUNTS RECEIVED FROM PAYMENTS MADE UNDER THE FIRST MORTGAGE BONDS. 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 reoffered in the aggregate principal amount set forth on the cover page of this Reoffering Circular. The Bonds will mature on June 1, 2033. The Bonds are also subject to optional redemption and extraordinary optional redemption, in whole or in part, and mandatory redemption prior to maturity as described in this Reoffering Circular.

The Bonds currently bear interest at a Long Term Rate to and including May 31, 2012. Pursuant to the terms and provisions of the Indenture summarized below, the Company has exercised its option, effective the Change Date, to change the existing Long Term Rate Period to a new Long Term Rate Period. The Bonds will bear interest at the Long Term Rate of 1.60% per annum from June 1, 2012, and will be subject to mandatory purchase following the expiration of this new Long Term Rate Period on June 1, 2017. Additional information regarding mandatory purchase is described below under the caption "— Mandatory Purchases of Bonds."

Following the expiration of the new Long Term Rate Period applicable to the Bonds, the Bonds will be subject to mandatory purchase, but will continue to bear interest at a Long Term Rate until a Conversion to another Interest Rate Mode is specified by the Company or until the redemption or maturity of the Bonds. Also, following the expiration of the new Long Term Rate Period, the Company may elect to change the Long Term Rate Period to a different Long Term Rate Period. 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 "Auction Rate." Changes in the Interest Rate Mode will be effected, and notice of such changes will be given, as described below under the caption "— Conversion of Interest Rate Modes."

This Reoffering Circular does not describe the terms and provisions of the Bonds and the documents related thereto while the Bonds bear interest at an Auction Rate. Provisions relating to the Bonds if they bear interest at an Auction Rate will be determined in accordance with auction procedures established at the time of any such conversion to the Auction Rate pursuant to the provisions of the Indenture.

Interest on the Bonds is payable on each June 1 and December 1, commencing December 1, 2012 (unless any such interest payment date is not a Business Day, in which case interest will be paid on the next succeeding Business Day), to the persons who are the registered owners of the Bonds as of the Record Date preceding such interest payment date. Interest also will be payable on the day following the end of the new Long Term Rate Period to the persons who are registered owners of the Bonds on the last day of such Long Term Rate Period. During each Rate Period for an Interest Rate Mode, 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.

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. 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, 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 $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, or (iii) denominations of $5,000 and integral multiples thereof, if bearing interest at the Semi-Annual Rate, 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 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, the Annual Rate or the 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.

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). 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 is further secured by a principal amount of First Mortgage Bonds of the Company which equals 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 Company is not required under the Loan Agreement or Indenture to provide any letter of credit or liquidity support for the Bonds. 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. See "Summary of the Bonds — Remarketing and Purchase of Bonds."

The Bonds Are Not Insured

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.

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 in this Reoffering Circular under the captions "— 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

J.P. Morgan Securities LLC will be appointed under the Indenture to serve as Remarketing Agent for the Bonds. 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.

Certain Definitions

As used in this Reoffering Circular, each of the following terms will have the meaning indicated. Certain capitalized terms used in this Reoffering Circular and not otherwise defined will have the meanings set forth in 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 Participant (as defined in this Reoffering Circular) 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 located in the city in which the principal office of the Trustee, the Bond Registrar, the Tender Agent, the Paying Agent, the Company 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.

"*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.

"*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.

"*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 also the day following the end of the initial Long Term Rate Period, the Conversion Date or the effective date of a change to a new Long Term Rate Period; and (iv) 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 the 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 the day immediately preceding the maturity date of the Bonds.

"*Interest Rate Mode*" means the Flexible Rate, the Daily Rate, the Weekly Rate, the Semi-Annual Rate, the Annual Rate and the Long Term Rate, as applicable.

"*Long Term Rate Period*" means any period established by the Company as set forth below under the caption "— 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.

"*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 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.

Summary of Certain Provisions of the Bonds

The following table summarizes, for each of the permitted Interest Rate Modes: 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 — Notices 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.

	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 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 Friday to and including the following Thursday.
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; and with respect to each Bond, on each Interest Payment Date for such Bond.	Any Conversion Date.	Any Conversion Date.
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 Redemption and Mandatory Purchases*	No notice of mandatory purchase following the end of each Flexible Rate Period; otherwise not fewer than 15 days (not fewer than 30 days notice of mandatory purchase on a Conversion Date if Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days.	Not fewer than 15 days (30 days notice of mandatory purchase if Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days.	Not fewer than 15 days (30 days notice of mandatory purchase if 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., and payments of principal, redemption and purchase price of and interest on the Bonds will be paid through the facilities of DTC. 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; the day following the end of the new Long Term Rate Period 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; 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.	Any Conversion Date; the first Business Day after the end of each Annual Rate Period.	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.
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 Redemption and Mandatory Purchases*	Not fewer than 30 days or greater than 45 days.	Not fewer than 30 days or greater than 45 days.	Not fewer than 30 days 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., and payments of principal, redemption and purchase price of and interest on the Bonds will be paid through the facilities of DTC. 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 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.

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 Long Term Rate Period will be five years (with the initial period ending May 31, 2017). 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 redemption or 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. As described under the caption, "— Mandatory Purchases of Bonds — Mandatory Purchase on Day after End of the Semi-Annual Rate Period, the Annual Rate Period or the Long Term Rate Period," the Bonds will be subject to mandatory purchase at the end of each Long Term Rate Period.

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 (i) 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 (ii) 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 under the Indenture to be set forth in such notice.

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 the caption "— Change of Long Term Rate Period" and below under the caption "— 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 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.

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; (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 Bonds 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 or a Long Term Rate) but not more than 45 days before each Conversion Date. The notice will state those matters required by the Indenture to be set forth in such notice.

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, the 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 Thursday) 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 Bond Registrar, the Tender Agent, the Company 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 in this Reoffering Circular, 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.

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 (i) 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 (ii) 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. When the Interest Rate Mode is in the Long Term Rate, the Bonds will not be subject to purchase on the demand of the registered owners thereof, but the Bonds will, however, be subject to mandatory purchase on each Conversion Date, each change in the Long Term Rate Period and at the end of each Long Term Rate Period, as described below under the caption "—Mandatory Purchases of Bonds." 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."

Notices Required for Purchases. Any written notice delivered to the Tender Agent by an owner demanding the purchase of the Bonds must (i) be delivered by the time and dates specified above, (ii) state the number and principal amount (or portion thereof) of such Bond to be purchased, (iii) state the Purchase Date on which such Bond is to be purchased and (iv) 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. (New York City time) on such Purchase Date (1:00 p.m. if a tender during a Daily Rate Period and 12:00 noon if a tender during a Weekly Rate Period).

Mandatory Purchases of Bonds

Mandatory Purchase on All Conversion Dates or Change by the Company in the Long Term Rate Period. The Bonds will be subject to mandatory purchase at a purchase price equal to the principal amount thereof, plus 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 (i) on each Conversion Date and (ii) 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, 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, the 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 the Bonds at a purchase price equal to the principal amount thereof plus accrued interest, if any, to such date. Following the end of the initial Long Term Rate Period, the Bonds will be subject to mandatory purchase on June 1, 2017.

Notice to Owners of Mandatory Purchases on a Conversion Date or upon Change in Long Term Rate Period. Notice to owners of a mandatory purchase of Bonds on a Conversion Date or upon a change in Long Term Rate Period will be given by the Bond Registrar, together with the notice of such Conversion or change of Long Term Rate Period 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 the 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. Notice to owners of a mandatory purchase of Bonds after the end of each Semi-Annual Rate Period, Annual Rate Period or Long Term Rate Period will be given by the Bond Registrar by first class mail at least 30 days prior to the end of such period. The notice of mandatory purchase will state those matters required by the Indenture to be set forth in such notice.

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 commercially reasonable best efforts to offer for sale Bonds purchased upon demand of the owners thereof and, unless otherwise instructed by the Company, 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.

The purchase price of Bonds tendered for purchase will be paid by the Tender Agent from moneys derived from the remarketing of such Bonds by the Remarketing Agent and, if such remarketing proceeds are insufficient, from moneys made available by the Company. The Company is obligated to purchase any Bonds tendered for purchase to the extent such Bonds have not been remarketed. Any such purchases by the Company will not result in the extinguishment of the purchased Bonds. The Company currently maintains lines of credit or other liquidity facilities in amounts determined by it to be sufficient to meet its current needs and expects to continue to maintain such lines of credit or other liquidity facilities from time to time to the extent determined by it to be necessary to meet its then current needs. The Trustee, any Paying Agent, the Tender Agent and the owners of the Bonds have no right to draw under any line of credit or other liquidity facility maintained by the Company. There is no provision in the Indenture or the Loan Agreement requiring the Company to maintain such financing arrangements which may be discontinued at any time without notice. The First Mortgage Bonds are not intended to provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase pursuant to the Indenture.

Any deficiency in purchase price payments resulting from the Remarketing Agent's failure to deliver remarketing proceeds of all Bonds with respect to which the Remarketing Agent notified the Tender Agent were remarketed will not result in an Event of Default under the Indenture until the opening of business on the next succeeding Business Day unless the Company fails to provide sufficient funds to pay such purchase price by the opening of business on such next succeeding Business Day. If sufficient funds are not available for the purchase of all tendered Bonds, no purchase of Bonds will be consummated, but failure to consummate such purchase will not be deemed to be an Event of Default under the Indenture if sufficient funds have been provided in a timely manner by the Company to the Tender Agent for such purpose.

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 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) 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**
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 has 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 any of 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 any of 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, the Company or the First Mortgage Trustee 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. 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 in this Reoffering Circular, 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 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 will 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 exhausts or chooses 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 in this Reoffering Circular.

General Redemption Terms. 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 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 in such notice 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 Indentures — 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 securities 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 3.5 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 is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation all of which are registered clearing agencies. DTC is owned by the users of its regulated subsidiaries. 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"). The DTC Rules applicable to its Participants are on file with the SEC. More information about DTC can be found at www.dtcc.com.

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 DTC 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 will 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 any 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 will give notice to elect to have its Bonds purchased or tendered, through its Participant, to the Tender Agent and will 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 decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor 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 printed and 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 in this Reoffering Circular 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 and the Company's obligations under the Loan Agreement and the First Mortgage Bonds, 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, the Tender Agent 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 TENDER AGENT, 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 (i) $5,000 and integral multiples thereof, if the Interest Rate Mode is the Semi-Annual Rate, the Annual Rate or the Long Term Rate; (ii) $100,000 and integral multiples of $5,000 in excess thereof, if the Interest Rate Mode is the Flexible Rate; and (iii) $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 above under the captions "— 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.

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 will end on the earliest to occur of the maturity date of the 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 (i) 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 and the Tender Agent, as may be applicable, under the Indenture, (ii) the expenses in connection with any redemption of the Bonds and (iii) 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 (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 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 obligation 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.

Issuance and Delivery of First Mortgage Bonds

For the purpose of providing security for the Bonds, the Company has executed and delivered to the Trustee the First Mortgage Bonds. The principal amount of the First Mortgage Bonds executed and delivered to the Trustee equals 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 tendered for purchase, 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 become 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 are registered in the name of the Trustee and are non-transferable, except to effect transfers to any successor trustee under the Indenture.

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 air and water pollution control and abatement facilities and solid waste disposal facilities under Section 103(b)(4)(E) and (F) 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 103(b)(4)(E) and (F) 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, the Company or the First Mortgage Trustee receives net proceeds from insurance or a condemnation award in connection therewith, the Company will (i) cause such net proceeds to be used to repair or restore the Project or (ii) take any other action, including the redemption of the Bonds in whole or in part at their principal amount, which, in 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."

Insurance

The Company will insure the Project in accordance with the provisions of the First Mortgage Indenture.

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 consolidates with or merges into must 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, must be qualified and admitted to do business in the Commonwealth of Kentucky, must assume in writing all of the obligations and covenants of the Company under the Loan Agreement and must deliver 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:

(i) 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 in the Indenture and the Bonds 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");

(ii) failure by the Company to observe and perform any covenant, condition or agreement, other than as referred to in paragraph (i) 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;

(iii) 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 by the First Mortgage Trustee;

(iv) certain events of bankruptcy, dissolution, liquidation, reorganization or insolvency of the Company; or

(v) 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.

In the event of a default in payment of the principal of, premium, if any, or interest on the Bonds, or a default in the payment of the purchase price of the Bonds tendered for purchase, 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.

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 will 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 or the Bond Registrar 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."

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. 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 the occurrence of an event of default under the Loan Agreement that has resulted in 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 any such Bonds tendered for purchase, 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, 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 First Mortgage 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 and the storage, transportation and distribution of gas (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 or its natural gas storage, transportation 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 or natural gas storage, transportation 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. As of March 31, 2012, first mortgage bonds in an aggregate principal amount of $1,109,304,000 were outstanding under the First Mortgage Indenture, of which $574,304,000 were issued to secure the Company's payment obligations with respect to its outstanding pollution control and environmental facilities revenue bonds, including the Bonds.

First mortgage bonds of any series may be issued from time to time in the future 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.

Future First Mortgage Bonds can be issued on the basis of *property additions*. At March 31, 2012, approximately $921 million 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 threehalves (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.

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.

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 will be further secured by the First Mortgage Bonds delivered to the Trustee (see "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds"). The First Mortgage Bonds will be registered in the name of the Trustee and will be nontransferable, except to effect a transfer to any successor trustee. The Bonds will not be directly secured by the Project (although the Project is subject to the lien of the First Mortgage Indenture).

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 are deposited into a Bond Fund that has been established pursuant to the Indenture (the "Bond Fund") and is maintained in trust by the Trustee. Moneys in the Bond Fund are used solely and only for the payment of the principal of, premium, if any, and interest on the Bonds, for the redemption of Bonds prior to maturity and for the payment of the reasonable fees and expenses to which the Trustee, Bond Registrar, Tender Agent, Authentication Agent, any Paying Agents and the Issuer are entitled pursuant to the Indenture or the Loan Agreement. Any moneys held in the Bond Fund are 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.

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 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 Authenticating Agent, the Bond Registrar, the Tender Agent and the Paying Agent have been paid or provided for.

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 (see "Discharge of Indenture" above), 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:

(i) 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;

(ii) 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, provided that no event of default has occurred in respect of failure to receive such purchase price for any Bond if the Company has made the payment on the next Business Day as described in the last paragraph under "Summary of the Bonds — Remarketing and Purchase of Bonds" above;

(iii) 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;

(iv) The occurrence of an "event of default" under the Loan Agreement (see "Summary of the Loan Agreement — Events of Default"); or

(v) 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 by the First Mortgage Trustee.

Upon the occurrence of an Event of Default under the Indenture, the Trustee may, and upon the written request of the registered owners holding not less than 25% in aggregate principal amount of Bonds then outstanding and upon receipt of indemnity reasonably satisfactory to it will: (i) enforce each and every right of the Trustee as a holder of the First Mortgage Bonds under the Supplemental Mortgage Indenture (see "Summary of the First Mortgage Bonds"), (ii) declare the principal of all Bonds and interest accrued thereon to be immediately due and payable and (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. 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 and may also issue a Redemption Demand for such First Mortgage Bonds to the First Mortgage Trustee.

If an Event of Default under paragraph (i), (ii), (iv) or (v) above 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. In the event the First Mortgage Bonds become due and payable, the principal of and all accrued interest on the Bonds shall be deemed to be paid solely to the extent of the moneys realized on the First Mortgage Bonds and any other moneys realized by the Trustee pursuant to any remedy exercised by it.

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.

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 (iii) 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 has 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.

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 has 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 has been obtained or entered, (i) the Company will cause 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 have 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 said 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.

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 (v) 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.

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.

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 shall 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 principal amount of all Bonds then outstanding.

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 modification or change to the Indenture necessary to provide liquidity or credit support for 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.

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 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 have consented to the execution thereof, no Bondholder will have any right to object or question the execution thereof.

No supplemental indenture may 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.

Enforceability of Remedies

The remedies available to the Trustee, the Issuer and the owners upon an event of default under the Loan Agreement, the Indenture or the First Mortgage 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, the Indenture or the First Mortgage 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 dated May 17, 2012 (the "Remarketing Agreement"), between the Company and J.P. Morgan Securities LLC, the Remarketing Agent has agreed to purchase and reoffer the Bonds delivered to the Paying Agent for purchase on June 1, 2012, 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 $132,000, 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.

The Remarketing Agent and its affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. In the ordinary course of their business, the Remarketing Agent and certain of its affiliates have, from time to time, performed, and may in the future perform, various investment banking services for the Company, for which they received or will receive customary fees and expenses.

Tax Treatment

On April 26, 2007, 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 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 Project or a "related person" as such terms are used in Section 147(a) of the Code. Interest on the Bonds would not 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 opinions are expressed by Bond Counsel.

Bond Counsel also will deliver an opinion in connection with this reoffering to the effect that the change of the Long Term Rate Period (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 opinion of Bond Counsel as to the excludability of interest from gross income for federal income tax purposes was 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 April 26, 2007, 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 Issuer 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 will 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:

(i) Provisions of the Code applicable to corporations (as defined for federal income tax purposes) which impose an alternative minimum tax on a portion of the excess of adjusted current earnings over other alternative minimum taxable income may subject a portion of the interest on the Bonds earned by certain corporations to such corporate alternative minimum tax. Such corporate alternative minimum tax does not apply to any S corporation, regulated investment company, real estate investment trust or REMIC. 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.

(ii) 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 change of the Long Term Rate Period for the Bonds in substantially the form in which it is expected to be delivered on the Change Date, redated to the Change Date, is attached as Appendix B-2.

Legal Matters

Certain legal matters in connection with the change in the Long Term Rate Period and 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 Dorothy O'Brien, Esq., Vice President and Deputy General Counsel, Legal and Environmental Affairs 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:

(i) The Company will provide to the Municipal Securities Rulemaking Board ("MSRB") (in electronic format) (a) annual financial information of the type set forth in Appendix A to this Reoffering Circular (including any information incorporated by reference in Appendix A) and (b) 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.

(ii) The Company will file in a timely manner not in excess of 10 business days after the occurrence of the event with the MSRB notice of the occurrence of any of the following events (if applicable) with respect to the Bonds: (a) principal and interest payment delinquencies; (b) non-payment related defaults, if material; (c) any unscheduled draws on debt service reserves reflecting financial difficulties; (d) unscheduled draws on credit enhancement facilities reflecting financial difficulties; (e) substitution of credit or liquidity providers, or their failure to perform; (f) adverse tax opinions, the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notices of Proposed Issue (IRS Form 5701-TEB) or other material notices or determinations with respect to the tax status of the Bonds, or other material events affecting the tax status of the Bonds; (g) modifications to rights of the holders of the Bonds, if material; (h) the giving of notice of optional or unscheduled redemption of any Bonds, if material, and tender offers; (i) defeasance of the Bonds or any portion thereof; (j) release, substitution, or sale of property securing repayment of the

Bonds, if material; (k) rating changes; (l) bankruptcy, insolvency, receivership or similar event of the Company; (m) the consummation of a merger, consolidation or acquisition involving the Company, or the sale of all of substantially all of the assets of the Company, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material; and (n) appointment of a successor or additional trustee or a change of name of a trustee, if material.

(iii) The Company will file in a timely manner with the MSRB notice of a failure by the Company to file any of the information referred to in paragraph (i) above by the due date.

The Company may amend its Continuing Disclosure Agreement (and the Trustee agrees 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 caption are intended to be for the benefit for the holders of the Bonds and will 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.

LOUISVILLE GAS AND ELECTRIC COMPANY

By: /s/ Daniel K. Arbough
Daniel K. Arbough
Treasurer

Appendix A

Louisville Gas and Electric Company

Louisville Gas and Electric Company ("LG&E"), incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. As of March 31, 2012, LG&E provides natural gas to approximately 319,000 customers and electricity to approximately 393,000 customers in Louisville and adjacent areas in Kentucky. LG&E's electric service area covers approximately 700 square miles in 9 counties. LG&E provides natural gas service in its electric service area and 8 additional counties. LG&E's coal-fired electric generating stations, all equipped with systems to reduce sulphur dioxide emissions, produce most of LG&E's electricity. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. Underground natural gas storage fields help LG&E provide economical and reliable natural gas service to customers.

LG&E is a wholly-owned subsidiary of LG&E and KU Energy LLC (the "Parent"). 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 a subsidiary of E.ON AG, making LG&E an indirect wholly-owned subsidiary of PPL Corporation ("PPL"). LG&E's affiliate, Kentucky Utilities Company ("KU"), is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee.

LG&E's executive offices are located at 220 West Main Street, Louisville, Kentucky 40202, telephone: (502) 627-2000.

Selected Financial Data

(Dollars in millions)

	Successor (1)				Predecessor (1)	
	Three Months Ended March 31, 2012	**Three Months Ended March 31, 2011**	**Year Ended December 31, 2011**	**November 1, 2010 through December 31, 2010**	**January 1, 2010 through October 31, 2010**	**Year Ended December 31, 2009**
Operating revenues	$ 353	$ 398	$ 1,364	$ 254	$ 1,057	$ 1,272
Operating income	$ 50	$ 73	$ 241	$ 40	$ 188	$ 167
Net income	$ 25	$ 39	$ 124	$ 19	$ 109	$ 95
Total assets	$ 4,383	$ 4,293	$ 4,387	$ 4,519	$ 3,699	$ 3,568
Long-term debt obligations (including amounts due within one year)	$ 1,112	$ 1,112	$ 1,112	$ 1,112	$ 896	$ 896
Ratio of earnings to fixed charges(2)	4.64	6.08	5.24	4.75	4.68	3.65

Capitalization:	March 31, 2012	% of Capitalization
Long-term debt and notes payable	$ 1,112	38.56%
Common equity	1,772	61.44%
Total capitalization	$ 2,884	100.00%

(1) LG&E's financial statements and related financial and operating data include the periods before and after PPL's acquisition of the Parent on November 1, 2010, and are labeled as "Predecessor" or "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. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in LG&E's Form 10-K for the year ended December 31, 2011 for additional information.

(2) For purposes of this ratio, "Earnings" consist of earnings (as defined below) from continuing operations plus fixed charges. Fixed charges consist of all interest on indebtedness, amortization of debt discount and expense and the portion of rental expense that represents an imputed interest component. Earnings from continuing operations consist of income before taxes and the mark-to-market impact of derivative instruments.

The selected financial data presented above for the three fiscal years ended December 31, 2011, and as of December 31 for each of those years, have been derived from LG&E's audited financial statements. The selected financial data presented above for the three months ended March 31, 2012 and 2011 have been derived from LG&E's unaudited financial statements for the three months ended March 31, 2012 and 2011. LG&E's audited financial statements for the three fiscal years ended December 31, 2011, and as of December 31 for each of those years, are included in LG&E's Form 10-K for the year ended December 31, 2011 incorporated by reference herein. LG&E's unaudited financial statements for the three months ended March 31, 2012 are included in LG&E's Form 10-Q for the quarter ended March 31, 2012 incorporated by reference herein. "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in LG&E's Form 10-K for the year ended December 31, 2011 and "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" in LG&E's Form 10-Q for the quarter ended March 31, 2012, as well as the Combined Notes to Financial Statements as of December 31, 2011, 2010 and 2009 and the Combined Notes to Condensed Financial Statements (Unaudited) as of March 31, 2012 and December 31, 2011 and for the three-month periods ended March 31, 2012 and 2011, should be read in conjunction with the above information. Ernst & Young LLP audited LG&E's financial statements for the fiscal year ended December 31, 2011. PricewaterhouseCoopers LLP audited LG&E's financial statements for the fiscal years ended December 31, 2010 and 2009.

Available Information

LG&E is subject to the information requirements of the Securities Exchange Act of 1934, as amended, and, accordingly, files reports, proxy statements and other information with the Securities and Exchange Commission (the "SEC"). Such reports, proxy statements and other information, can be inspected and copied at the public reference facilities of the SEC, currently at 100 F Street, N.E., Washington, D.C. 20549; and copies of such material can be obtained from the Public Reference Section of the SEC at its principal office of 100 F Street, N.E., Washington, D.C. 20549 at prescribed rates or from the SEC's Web Site (http://www.sec.gov). Please call the SEC at 1-800-SEC-0330 for further information on the operation of the public reference facilities.

Documents Incorporated By Reference

The following document, as filed by LG&E with the SEC, is incorporated herein by reference:

1. Form 10-K Annual Report of LG&E for the year ended December 31, 2011; and

2. Form 10-Q Quarterly Report of LG&E for the quarter ended March 31, 2012.

All documents filed by LG&E with the SEC pursuant to Section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 subsequent to the date of this Reoffering Circular and prior to the termination of the reoffering of the Bonds shall be deemed to be incorporated by reference in this Appendix and to be made a part hereof from their respective dates of filing. Any statement contained in a document incorporated or deemed to be incorporated by reference in this Reoffering Circular shall be deemed to be modified or superseded for purposes of this

Reoffering Circular to the extent that a statement contained in this Reoffering Circular or in any other subsequently filed document which also is or is deemed to be incorporated by reference in this Reoffering Circular modifies or supersedes such statement. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Reoffering Circular.

LG&E hereby undertakes to provide without charge to each person (including any beneficial owner) to whom a copy of this Reoffering Circular has been delivered, on the written or oral request of any such person, a copy of any or all of the documents referred to above which have been or may be incorporated in this Reoffering Circular by reference, other than certain exhibits to such documents. Requests for such copies should be directed to Daniel K. Arbough, Louisville Gas and Electric Company, 220 West Main Street, Louisville, Kentucky 40202, telephone: (502) 627-2000.

Appendix B

Opinion of Bond Counsel and
Form of Opinion of Bond Counsel

Appendix B-1

Opinion of Bond Counsel dated April 26, 2007

STOLL·KEENON·OGDEN
PLLC

2000 PNC PLAZA
500 WEST JEFFERSON STREET
LOUISVILLE, KENTUCKY 40202-2828
502-333-6000
FAX: 502-333-6099
WWW.SKOFIRM.COM

April 26, 2007

Re: $35,200,000 "Louisville/Jefferson County Metro Government, Kentucky, Environmental Facilities Revenue Refunding Bonds, 2007 Series B (Louisville Gas and Electric Company Project)"

We hereby certify that we have examined certified copies of the proceedings of record of the Louisville/Jefferson County Metro Government, Kentucky (the "Issuer"), being the governmental successor by operation of law to the County of Jefferson, Kentucky (the "Predecessor County"), acting by and through its Metro Council as its duly authorized governing body, preliminary to and in connection with the issuance by the Issuer of its Environmental Facilities Revenue Refunding Bonds, 2007 Series B (Louisville Gas and Electric Company Project), dated their date of issuance, in the aggregate principal amount of $35,200,000 (the "Bonds"). The Bonds are issued under the provisions of Chapter 67C and 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 Louisville Gas and Electric Company (the "Company") for the current refunding of $35,200,000 aggregate principal amount of the Predecessor County's Pollution Control Revenue Bonds, 1993 Series A (Louisville Gas and Electric Company Project), dated August 31, 1993 (the "Prior Bonds"), which were issued for the purpose of currently refunding a portion of the capital costs of facilities for the control, containment, reduction and abatement of atmospheric and liquid pollutants and contaminants and for the disposal of solid wastes serving the Mill Creek and Cane Run Generating Stations of the Company in Jefferson County, Kentucky (the "Project"), as provided by the Act.

The Bonds mature on June 1, 2033 and bear interest initially at the 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 Metro Council of the Issuer referred to above and from an examination of the Act, we are of the opinion that the Issuer 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 March 1, 2007 (the "Loan Agreement"), between the Issuer and the Company and a certified copy of the proceedings of record of the Metro Council of the Issuer preliminary to and in connection with the execution and delivery of the Loan Agreement, pursuant to which the Issuer 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 Metro Council of the Issuer 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 Issuer; and that the Loan Agreement is a legal, valid and binding obligation of the Issuer, 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 March 1, 2007 (the "Indenture"), by and between the Issuer and Deutsche Bank Trust Company Americas, as trustee (the "Trustee"), securing the Bonds and setting forth the covenants and undertakings of the Issuer in connection with the Bonds and a certified copy of the proceedings of record of the Metro Council of the Issuer preliminary to and in connection with the execution and delivery of the Indenture. Pursuant to the Indenture, certain of the Issuer'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 Metro Council of the Issuer show lawful authority for the execution and delivery of the Indenture; that the Indenture has been duly authorized, executed and delivered by the Issuer; 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 Issuer 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 Issuer 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 not 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 substantially all of the proceeds of the Prior Bonds were used to refinance air and water pollution control facilities and solid waste disposal facilities qualified for financing under Section 103(b)(4)(E) and (F) of the Internal Revenue Code of 1954, 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 accuracy of and continuing compliance by the Company and the Issuer 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) Provisions of the Code applicable to corporations (as defined for federal income tax purposes) which impose an alternative minimum tax on a portion of the excess of adjusted current earnings over other alternative minimum taxable income may subject a portion of the interest on the Bonds earned by certain corporations to such corporate alternative minimum tax. Such corporate alternative minimum tax does not apply to any S corporation, regulated investment company, real estate investment trust or REMIC.

(b) 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.

(c) 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. Irv Maze, County Attorney of Jefferson County, Kentucky and the chief legal officer of the Issuer, 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

Form of Opinion of Bond Counsel

June 1, 2012

Re: Change in Long Term Rate Period of $35,200,000 "Louisville/Jefferson County Metro Government, Kentucky, Environmental Facilities Revenue Refunding Bonds, 2007 Series B (Louisville Gas and Electric Company Project)"

Ladies and Gentlemen:

This opinion is being furnished in accordance with the requirements of the Amended and Restated Indenture of Trust, dated as of November 1, 2010 (the "Indenture"), between the Louisville/Jefferson County Metro Government, Kentucky (the "Issuer") and Deutsche Bank Trust Company Americas, as Trustee, Bond Registrar, Paying Agent and Tender Agent (the "Trustee"), pertaining to $35,200,000 principal amount of Louisville/Jefferson County Metro Government, Kentucky, Environmental Facilities Revenue Refunding Bonds, 2007 Series B (Louisville Gas and Electric Company Project), dated April 26, 2007 (the "Bonds"), in order to satisfy certain requirements of Section 2.02(d)(ii) of the Indenture. Pursuant to Section 2.02(d)(ii) of the Indenture, the Company has elected to change the existing Long Term Rate Period applicable to the Bonds expiring on May 31, 2012 to a new Long Term Rate Period applicable to the Bonds commencing on and effective as of June 1, 2012 and ending on May 31, 2017. The Bonds will be subject to mandatory tender for purchase on June 1, 2017 following the expiration of the new Long Term Rate Period. The Bonds mature on June 1, 2033. 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 change in the Long Term Rate Period applicable to the Bonds expiring on May 31, 2012 to a new Long Term Rate Period commencing on and effective as of June 1, 2012 and ending on May 31, 2017 as described herein (a) is authorized or permitted by the Act and is authorized by the Indenture and (b) will not adversely affect the validity of the Bonds or any exclusion from gross income of the interest on the Bonds 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 Amended and Restated Loan Agreement between the Issuer and the Company, dated as of November 1, 2010, 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

Louisville Gas and Electric Company
Case No. 2012-00222
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 LG&E's shareholders during the period referenced. LG&E 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 LG&E 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 LG&E relating to the period described are provided in Filing Requirement 807 KAR 5:001 Section 10(6)(s) [Tab No. 38].)

Louisville Gas and Electric Company
Case No. 2012-00222
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.

LOUISVILLE GAS AND ELECTRIC COMPANY

Financial Reports

March 31, 2012

Index
Financial and Operating Reports

Louisville Gas and Electric 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.

Louisville Gas and Electric Company
Comparative Statement of Income
March 31, 2012

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 80,159,282.52	$ 82,777,821.36	$ (2,618,538.84)	(3.16)
Gas Operating Revenues	23,666,489.53	34,497,178.98	(10,830,689.45)	(31.40)
Total Operating Revenues	103,825,772.05	117,275,000.34	(13,449,228.29)	(11.47)
Fuel for Electric Generation	29,806,959.77	28,128,732.02	1,678,227.75	5.97
Power Purchased	4,707,080.96	6,491,986.81	(1,784,905.85)	(27.49)
Gas Supply Expenses	8,869,275.78	18,277,470.30	(9,408,194.52)	(51.47)
Other Operation Expenses	20,103,047.79	21,074,094.42	(971,046.63)	(4.61)
Maintenance	12,050,118.95	13,016,624.79	(966,505.84)	(7.43)
Depreciation	12,009,763.52	11,654,406.51	355,357.01	3.05
Amortization Expense	736,955.24	647,548.98	89,406.26	13.81
Regulatory Credits	(446,222.39)	(368,446.61)	(77,775.78)	(21.11)
Taxes				
Federal Income	(12,307,098.86)	(10,334,822.63)	(1,972,276.23)	(19.08)
State Income	(621,707.01)	173,062.26	(794,769.27)	(459.24)
Deferred Federal Income - Net	15,059,088.67	13,658,478.51	1,400,610.16	10.25
Deferred State Income - Net	847,565.83	341,927.36	505,638.47	147.88
Property and Other	2,369,840.46	2,359,410.78	10,429.68	0.44
Amortization of Investment Tax Credit	(223,357.47)	(236,034.00)	12,676.53	5.37
Loss (Gain) from Disposition of Allowances	(693.97)	(2,577.94)	1,883.97	73.08
Accretion Expense	242,872.24	220,545.82	22,326.42	10.12
Total Operating Expenses	93,203,489.51	105,102,407.38	(11,898,917.87)	(11.32)
Net Operating Income	10,622,282.54	12,172,592.96	(1,550,310.42)	(12.74)
Other Income Less Deductions	(554,124.33)	(1,185,811.78)	631,687.45	53.27
Income Before Interest Charges	10,068,158.21	10,986,781.18	(918,622.97)	(8.36)
Interest on Long-Term Debt	3,123,496.81	3,263,094.72	(139,597.91)	(4.28)
Amortization of Debt Expense - Net	262,322.89	275,309.84	(12,986.95)	(4.72)
Other Interest Expenses	266,432.07	156,487.63	109,944.44	70.26
Total Interest Charges	3,652,251.77	3,694,892.19	(42,640.42)	(1.15)
Net Income	$ 6,415,906.44	$ 7,291,888.99	$ (875,982.55)	(12.01)

April 26, 2012

Louisville Gas and Electric Company
Comparative Statement of Income
March 31, 2012

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 244,420,426.43	$ 256,266,504.32	$ (11,846,077.89)	(4.62)
Gas Operating Revenues..	108,809,879.08	137,442,353.62	(28,632,474.54)	(20.83)
Total Operating Revenues..	353,230,305.51	393,708,857.94	(40,478,552.43)	(10.28)
Fuel for Electric Generation..	91,719,151.25	88,269,821.95	3,449,329.30	3.91
Power Purchased...	13,783,932.99	19,611,301.06	(5,827,368.07)	(29.71)
Gas Supply Expenses..	57,345,602.29	83,628,346.24	(26,282,743.95)	(31.43)
Other Operation Expenses...	58,884,895.86	58,730,273.53	154,622.33	0.26
Maintenance..	35,586,242.09	27,660,089.18	7,926,152.91	28.66
Depreciation..	35,897,362.32	34,530,041.35	1,367,320.97	3.96
Amortization Expense...	2,177,175.30	1,929,384.09	247,791.21	12.84
Regulatory Credits..	(1,335,588.73)	(1,102,609.68)	(232,979.05)	(21.13)
Taxes				
Federal Income..	(2,200,973.02)	6,012,136.68	(8,213,109.70)	(136.61)
State Income...	1,222,084.95	3,154,270.64	(1,932,185.69)	(61.26)
Deferred Federal Income - Net...................................	15,135,238.66	13,658,485.33	1,476,753.33	10.81
Deferred State Income - Net.......................................	847,565.83	341,927.36	505,638.47	147.88
Property and Other...	7,299,098.74	6,927,442.73	371,656.01	5.37
Amortization of Investment Tax Credit.....................	(670,069.47)	(681,435.00)	11,365.53	1.67
Loss (Gain) from Disposition of Allowances...............	(693.97)	(2,577.94)	1,883.97	73.08
Accretion Expense..	725,537.76	658,810.60	66,727.16	10.13
Total Operating Expenses..	316,416,562.85	343,325,708.12	(26,909,145.27)	(7.84)
Net Operating Income...	36,813,742.66	50,383,149.82	(13,569,407.16)	(26.93)
Other Income Less Deductions..................................	(923,118.22)	(186,813.93)	(736,304.29)	(394.14)
Income Before Interest Charges.................................	35,890,624.44	50,196,335.89	(14,305,711.45)	(28.50)
Interest on Long-Term Debt..	9,267,123.12	9,816,625.40	(549,502.28)	(5.60)
Amortization of Debt Expense - Net.............................	786,961.09	823,329.37	(36,368.28)	(4.42)
Other Interest Expenses...	647,444.99	460,933.33	186,511.66	40.46
Total Interest Charges..	10,701,529.20	11,100,888.10	(399,358.90)	(3.60)
Net Income..	$ 25,189,095.24	$ 39,095,447.79	$ (13,906,352.55)	(35.57)

April 26, 2012

Louisville Gas and Electric Company
Comparative Statement of Income
March 31, 2012

	Year Ended Current Month			
	This Year	Last Year	Increase or Decrease	
	Amount	Amount	Amount	%
Electric Operating Revenues	$ 1,047,904,225.60	$ 1,041,582,725.86	$ 6,321,499.74	0.61
Gas Operating Revenues	275,941,947.28	304,684,577.93	(28,742,630.65)	(9.43)
Total Operating Revenues	1,323,846,172.88	1,346,267,303.79	(22,421,130.91)	(1.67)
Fuel for Electric Generation	364,417,722.66	373,684,099.84	(9,266,377.18)	(2.48)
Power Purchased	69,067,179.05	57,504,358.85	11,562,820.20	20.11
Gas Supply Expenses	134,952,881.75	169,633,960.88	(34,681,079.13)	(20.44)
Other Operation Expenses	236,431,977.22	230,716,875.87	5,715,101.35	2.48
Maintenance	124,285,221.46	113,372,416.95	10,912,804.51	9.63
Depreciation	143,365,535.89	133,359,544.69	10,005,991.20	7.50
Amortization Expense	8,381,255.24	7,524,041.54	857,213.70	11.39
Regulatory Credits	(5,963,064.74)	(4,832,257.91)	(1,130,806.83)	(23.40)
Taxes				
Federal Income	3,749,740.75	21,789,438.31	(18,039,697.56)	(82.79)
State Income	6,333,346.98	6,953,660.33	(620,313.35)	(8.92)
Deferred Federal Income - Net	53,700,477.69	38,446,565.63	15,253,912.06	39.68
Deferred State Income - Net	2,517,313.82	2,136,319.63	380,994.19	17.83
Property and Other	28,493,239.65	23,317,903.98	5,175,335.67	22.19
Amortization of Investment Tax Credit	(2,794,366.47)	(2,557,764.00)	(236,602.47)	(9.25)
Loss (Gain) from Disposition of Allowances	(693.97)	(2,577.94)	1,883.97	73.08
Accretion Expense	2,711,211.78	3,446,752.28	(735,540.50)	(21.34)
Total Operating Expenses	1,169,648,978.76	1,174,493,338.93	(4,844,360.17)	(0.41)
Net Operating Income	154,197,194.12	171,773,964.86	(17,576,770.74)	(10.23)
Other Income Less Deductions	343,093.48	9,924,162.58	(9,581,069.10)	(96.54)
Income Before Interest Charges	154,540,287.60	181,698,127.44	(27,157,839.84)	(14.95)
Interest on Long-Term Debt	38,260,233.51	42,683,526.08	(4,423,292.57)	(10.36)
Amortization of Debt Expense - Net	3,275,104.95	2,138,899.58	1,136,205.37	53.12
Other Interest Expenses	2,724,996.26	2,515,569.32	209,426.94	8.33
Total Interest Charges	44,260,334.72	47,337,994.98	(3,077,660.26)	(6.50)
Net Income	$ 110,279,952.88	$ 134,360,132.46	$ (24,080,179.58)	(17.92)

April 26, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings
March 31, 2012

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period...	$ 872,702,746.19	$ 842,546,810.76	$ 868,929,557.39	$ 827,993,251.96	$ 849,838,699.75	$ 757,728,567.29
Add:						
Net Income for Period..	6,415,906.44	7,291,888.99	25,189,095.24	39,095,447.79	110,279,952.88	134,360,132.46
Deduct:						
Common Dividends						
Common Stock Without Par Value.....................	-	-	15,000,000.00	17,250,000.00	81,000,000.00	42,250,000.00
Balance at End of Period...	$ 879,118,652.63	$ 849,838,699.75	$ 879,118,652.63	$ 849,838,699.75	$ 879,118,652.63	$ 849,838,699.75

April 26, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of March 31, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,933,705,788.03	$ 4,770,490,279.22
Less: Reserves for Depreciation and Amortization	2,144,260,445.77	2,068,083,714.02
Total	2,789,445,342.26	2,702,406,565.20
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	26,812,546.91	20,180,403.81
Total	27,418,712.11	20,786,569.01
Current and Accrued Assets		
Cash	37,944,606.65	28,355,866.45
Special Deposits	-	4,098,610.17
Temporary Cash Investments	16,338,854.02	2,431.80
Accounts Receivable - Less Reserve	121,482,082.46	133,817,500.02
Accounts Receivable from Associated Companies	20,097,723.37	24,396,918.17
Materials and Supplies - At Average Cost		
Fuel	66,393,015.44	67,368,406.54
Plant Materials and Operating Supplies	30,964,056.64	30,050,637.73
Stores Expense	5,553,099.47	5,108,104.12
Gas Stored Underground	20,184,889.10	19,475,230.55
Emission Allowances	17,221.12	2,444.82
Prepayments	4,804,662.67	6,469,399.17
Miscellaneous Current and Accrued Assets	693.97	941,878.08
Total	323,780,904.91	320,087,427.62
Deferred Debits and Other		
Unamortized Debt Expense	12,916,551.41	13,460,450.73
Unamortized Loss on Bonds	20,682,089.39	21,631,640.60
Accumulated Deferred Income Taxes	22,116,906.94	53,426,611.12
Deferred Regulatory Assets	388,800,142.12	357,236,196.73
Other Deferred Debits	1,804,929.40	1,328,343.09
Total	446,320,619.26	447,083,242.27
Total Assets	$ 3,586,965,578.54	$ 3,490,363,804.10

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	879,118,652.63	849,838,699.75
Total Proprietary Capital	1,387,034,687.08	1,357,754,734.20
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,401,507.42	531,121,647.48
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,105,705,507.42	1,105,425,647.48
Total Capitalization	2,492,740,194.50	2,463,180,381.68
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	-	-
Accounts Payable	92,234,601.80	75,673,663.92
Accounts Payable to Associated Companies	15,938,027.00	14,546,268.31
Customer Deposits	22,435,650.26	23,240,672.59
Taxes Accrued	17,874,000.30	18,309,170.54
Dividends Declared	-	-
Interest Accrued	12,083,404.23	11,708,678.03
Miscellaneous Current and Accrued Liabilities	28,854,345.46	32,140,201.55
Total	189,420,029.05	175,618,654.94
Deferred Credits and Other		
Accumulated Deferred Income Taxes	515,319,247.11	487,780,888.27
Investment Tax Credit	42,048,774.66	44,843,141.13
Regulatory Liabilities	58,003,499.13	62,145,912.07
Customer Advances for Construction	7,329,863.59	8,163,578.28
Asset Retirement Obligations	59,331,864.27	53,309,599.51
Other Deferred Credits	8,148,016.44	12,660,924.88
Miscellaneous Long-Term Liabilities	53,954,916.00	34,448,469.13
Accum Provision for Postretirement Benefits	160,669,173.79	148,212,254.21
Total	904,805,354.99	851,564,767.48
Total Liabilities and Stockholders' Equity	$ 3,586,965,578.54	$ 3,490,363,804.10

April 26, 2012

Louisville Gas and Electric 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.........	75,000,000	21,294,223	$ 425,170,424.09	
Less: Common Stock Expense.........			835,888.64	
Paid-In Capital.........			83,581,499.00	
Other Comprehensive Income.........			-	
Retained Earnings.........			879,118,652.63	
Total Proprietary Capital.........			1,387,034,687.08	55.64
Long-Term Debt				
Pollution Control Bonds.........				
Jefferson County 2000 Series A due 05/01/27 5.375%.........			25,000,000.00	
Trimble County 2000 Series A due 08/01/30 Var%.........			83,335,000.00	
Jefferson County 2001 Series A due 09/01/26 Var%.........			22,500,000.00	
Jefferson County 2001 Series A due 09/01/27 Var%.........			10,104,000.00	
Jefferson County 2001 Series B due 11/01/27 Var%.........			35,000,000.00	
Trimble County 2001 Series A due 09/01/26 Var%.........			27,500,000.00	
Trimble County 2001 Series A due 10/01/32 Var%.........			41,665,000.00	
Trimble County 2001 Series B due 11/01/27 Var%.........			35,000,000.00	
Louisville Metro 2003 Series A due 10/01/33 1.900%.........			128,000,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%.........			40,000,000.00	
Louisville Metro 2007 Series A due 06/01/33 5.625%.........			31,000,000.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%.........			35,200,000.00	
Trimble County 2007 Series A due 06/01/33 4.600%.........			60,000,000.00	
Total Pollution Control Bonds.........			574,304,000.00	23.04
First Mortgage Bonds.........				
First Mortgage Bond Due 11/15/15 1.625%.........			250,000,000.00	
First Mortgage Bond Due 11/15/40 5.125%.........			285,000,000.00	
Total First Mortgage Bonds.........			535,000,000.00	21.46
Less: First Mortgage Bonds Debt Discount.........				
First Mortgage Bond Due 11/15/15 1.625%.........			(639,812.54)	
First Mortgage Bond Due 11/15/40 5.125%.........			(2,958,680.04)	
			(3,598,492.58)	(0.14)
Total First Mortgage Bonds - Net of Debt Discount.........			531,401,507.42	21.32
Total Capitalization.........			$ 2,492,740,194.50	100.00

April 26, 2012

Louisville Gas and Electric Company
Summary Trial Balance
March 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 4,933,705,788.03	$ 4,933,705,788.03
Reserves for Depreciation and Amortization		(2,144,260,445.77)
Depreciation of Plant		
Electric	(1,802,261,255.06)	
Gas	(240,756,443.74)	
Common	(80,187,908.22)	
Amortization of Plant		
Common	(21,054,838.75)	
Investments		27,418,712.11
Special Funds	26,812,546.91	
Ohio Valley Electric Corporation	594,286.00	
Nonutility Property	11,879.20	
Cash	37,944,606.65	37,944,606.65
Temporary Cash Investments	16,338,854.02	16,338,854.02
Accounts Receivable - Less Reserve		121,482,082.46
Customers - Active	63,933,104.08	
Unbilled Revenues	49,315,618.55	
Income Tax Receivable - Federal	2,527,696.74	
IMPA	2,514,148.14	
IMEA	2,473,115.45	
Sundry Accounts Receivable	832,725.31	
Wholesale Sales	439,543.94	
Transmission Sales	428,207.77	
Damage Claims	424,692.03	
Electricity Swaps	166,354.87	
Bechtel Liquidated Damages	5,890.00	
Other	594,386.99	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	1,186,153.41	
Reserve	(1,626,196.00)	
Accrual	(809,191.56)	
A/R Miscellaneous	(380,850.54)	
Recoveries	(376,961.85)	
LEM Reserve	(166,354.87)	
Accounts Receivable from Associated Companies		20,097,723.37
LG&E and KU Services/Kentucky Utilities	20,097,723.37	
Fuel		66,393,015.44
Coal 1,259,092.96 Tons @ $52.31; MMBtu 28,317,503.94 @ 232.59¢	65,863,838.51	
Fuel Oil 185,161.85 Gallons @ 277.99¢	514,724.75	
Gas Pipeline 4,700 mcf @ $3.07	14,452.18	
Plant Materials and Operating Supplies		30,964,056.64
Regular Materials and Supplies	30,074,449.46	
Limestone 96,488.39 Tons @ $9.22	889,607.17	
Carbide Lime	0.01	
Stores Expense Undistributed	5,553,099.47	5,553,099.47
Gas Stored Underground - Current		20,184,889.10
Gas Stored Underground* 4,345,384 Mcf (14.73 psia) @ $4.65	20,184,889.10	
Emission Allowances	17,221.12	17,221.12

April 26, 2012

Louisville Gas and Electric Company
Summary Trial Balance
March 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Prepayments		$ 4,804,662.67
Insurance	1,351,779.60	
Taxes	488,659.86	
Franchises	312,418.23	
Rights of Way	226,666.71	
Risk Management and Workers Compensation	90,000.00	
Other	2,335,138.27	
Miscellaneous Current Assets		693.97
Miscellaneous Current Assets	693.97	
Unamortized Debt Expense		12,916,551.41
Trimble County 2000 Series A due 08/01/30 Var%	709,635.21	
Jefferson County 2001 Series A due 09/01/26 Var%	143,067.72	
Jefferson County 2001 Series A due 09/01/27 Var%	314,384.26	
Jefferson County 2001 Series B due 11/01/27 Var%	171,342.65	
Trimble County 2001 Series A due 09/01/26 Var%	155,555.57	
Trimble County 2001 Series B due 11/01/27 Var%	171,370.76	
Trimble County 2002 Series A due 10/01/32 Var%	763,038.99	
Louisville Metro 2003 Series A Due 10/01/33 1.900%	427,560.22	
Louisville Metro 2007 Series B Due 06/01/33 1.900%	164,160.41	
Trimble County 2007 Series A due 06/01/33 4.600%	1,006,145.06	
First Mortgage Bond due 11/15/15 1.625%	1,889,239.30	
First Mortgage Bond due 11/15/40 5.125%	3,412,849.60	
Revolving Credit Agreement	3,588,201.66	
Unamortized Loss on Bonds	20,682,089.39	20,682,089.39
Accumulated Deferred Income Taxes		22,116,906.94
Federal		
Electric	16,361,514.44	
Gas	1,226,383.55	
State		
Electric	4,253,237.01	
Gas	275,771.94	
Regulatory Assets		388,800,142.12
Pension and Postretirement Benefits	220,425,085.00	
Interest Rate Swap Ineffectiveness	52,928,029.91	
2009 Winter Storm	36,531,992.69	
2008 Wind Storm	19,616,943.99	
Deferred Taxes - ASC 740		
Federal		
Electric	12,371,961.27	
State		
Electric	2,256,284.73	
Asset Retirement Obligations		
Electric	10,309,632.19	
Gas	1,681,625.17	
Common	11,115.07	
Swap Termination	8,872,602.80	
2011 Summer Storm	8,052,124.65	
Gas Supply Clause/PBR	7,087,748.69	
Fuel Adjustment Clause	6,382,000.00	
Rate Case Expenses	612,131.35	
MISO Exit Fee	572,174.10	
KCCS Funding	512,190.30	
EKPC FERC Transmission Costs	325,013.68	
CMRG Funding	130,080.00	
General Management Audit	121,406.53	
Other Deferred Debits	1,804,929.40	1,804,929.40
Total Assets	$ 3,586,965,578.54	$ 3,586,965,578.54

* Excludes:		$	Mcf
	Non-recoverable Base Gas	9,648,855.00	7,880,000
	Recoverable Base Gas	2,139,990.00	2,930,000
		11,788,845.00	10,810,000

April 26, 2012

Louisville Gas and Electric Company
Summary Trial Balance
March 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 1,387,034,687.08
Common Stock	425,170,424.09	
Less: Common Stock Expense	835,888.64	
Paid-In Capital	83,581,499.00	
Retained Earnings	879,118,652.63	
Pollution Control Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,401,507.42	531,401,507.42
Accounts Payable		92,234,601.80
Regular	88,919,523.41	
Salaries and Wages Accrued	3,186,434.04	
Employee Withholdings Payable	128,644.35	
Accounts Payable to Associated Companies		15,938,027.00
LG&E and KU Services/Kentucky Utilities	15,938,027.00	
Customers' Deposits	22,435,650.26	22,435,650.26
Taxes Accrued	17,874,000.30	17,874,000.30
Interest Accrued		12,083,404.23
Jefferson County 2000 Series A due 05/01/27 5.375%	17,484.38	
Trimble County 2000 Series A due 08/01/30 Var%	5,833.45	
Jefferson County 2001 Series A due 09/01/26 Var%	6,670.08	
Jefferson County 2001 Series A due 09/01/27 Var%	280.67	
Jefferson County 2001 Series B due 11/01/27 Var%	4,234.97	
Trimble County 2001 Series A due 09/01/26 Var%	3,125.68	
Trimble County 2001 Series A due 10/01/32 Var%	2,868.74	
Trimble County 2001 Series B due 11/01/27 Var%	4,303.28	
Louisville Metro 2003 Series A due 10/01/33 1.900%	1,216,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%	376,944.44	
Louisville Metro 2007 Series A due 06/01/33 5.625%	581,250.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%	222,933.33	
Trimble County 2007 Series A due 06/01/33 4.600%	920,000.00	
Interest Rate Swaps	672,379.45	
First Mortgage Bond due 11/15/15 1.625%	1,534,722.22	
First Mortgage Bond due 11/15/40 5.125%	5,517,916.67	
Customers' Deposits	909,913.33	
Interest Accrued on Tax Liabilities	79,624.00	
Other	6,919.54	
Miscellaneous Current and Accrued Liabilities		28,854,345.46
No-Notice Gas Payable	8,380,102.37	
Vacation Pay Accrued	6,593,096.94	
Customer Overpayments	6,444,317.27	
Derivative Liability - ASC 815	4,276,007.74	
Tax Collections Payable	2,110,281.23	
Home Energy Assistance	649,249.68	
Unearned Revenue	189,983.60	
Other	211,306.63	

Louisville Gas and Electric Company
Summary Trial Balance
March 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Accumulated Deferred Income Taxes		$ 515,319,247.11
Federal		
Electric	370,664,947.50	
Gas	76,782,495.35	
State		
Electric	56,724,075.39	
Gas	11,147,728.87	
Investment Tax Credit		42,048,774.66
Advanced Coal Credit	22,976,499.51	
Job Development Credit		
Electric	18,547,473.99	
Gas	524,801.16	
Regulatory Liabilities		58,003,499.13
Deferred Taxes		
Federal		
Electric	26,889,784.25	
Gas	998,105.77	
State		
Electric	14,865,490.98	
Gas	2,419,840.18	
Gas Supply Clause/PBR	5,332,069.28	
DSM Cost Recovery	3,710,042.25	
Asset Retirement Obligations		
Gas	2,155,824.27	
Electric	204,350.68	
MISO Schedule 10 Charges	680,643.16	
Purchased Gas Adjustment - Tennessee Gas	392,541.31	
Environmental Cost Recovery	354,807.00	
Customers' Advances for Construction		7,329,863.59
Line Extensions		
Gas	6,368,916.77	
Electric	960,946.82	
Asset Retirement Obligations		59,331,864.27
Electric	37,261,095.38	
Gas	21,961,182.74	
Common	109,586.15	
Other Deferred Credits	8,148,016.44	8,148,016.44
Miscellaneous Long-Term Liabilities		53,954,916.00
Long-Term Derivative Liabilities - ASC 815	48,652,022.17	
Workers' Compensation	5,302,893.83	
Accumulated Provision for Benefits		160,669,173.79
Postretirement Benefits - ASC 715	84,686,600.29	
Pension Payable	72,497,083.50	
Post Employment Benefits Payable	3,689,805.00	
Post Employment Medicare Subsidy	(204,315.00)	
Total Liabilities and Stockholders' Equity	$ 3,586,965,578.54	$ 3,586,965,578.54

April 26, 2012

Louisville Gas and Electric Company
Statement of Cash Flows
March 31, 2012

	Year to Date 2012	Year to Date 2011
Cash Flows from Operating Activities		
Net income	$ 25,189,095.24	$ 39,095,447.79
Items not requiring (providing) cash currently:		
Depreciation	35,897,362.32	34,530,041.35
Amortization	2,177,175.30	1,929,384.09
Deferred income taxes - net	17,372,564.62	14,705,441.27
Investment tax credit - net	(670,069.47)	(681,435.00)
Gain on disposal of assets	(1,261.11)	(1,034.71)
Other	6,873,857.24	4,166,033.15
Change in receivables	7,820,068.87	34,091,537.19
Change in inventory	18,905,929.42	40,267,160.84
Change in allowance inventory	(14,709.45)	284.14
Change in payables and accrued expenses	2,045,092.31	(14,866,408.76)
Change in regulatory assets	8,312,134.55	(9,369,464.61)
Change in regulatory liabilities	(614,097.27)	10,719,563.61
Change in other deferred debits	(1,973,088.66)	(7,054,772.62)
Change in other deferred credits	3,201,563.97	7,109,841.60
Pension and postretirement funding	(23,698,900.00)	(65,337,400.00)
Other	1,778,103.28	4,075,251.90
Net cash provided (used) by operating activities	102,600,821.16	93,379,471.23
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(53,176,834.50)	(34,222,027.70)
Gross additions to common utility plant - construction expenditures	(2,060,586.53)	547,629.83
Proceeds received from sales of property	1,261.11	1,034.71
Change in restricted cash	2,046,460.29	(1,854,248.90)
Change in derivatives	-	3,778.13
Other	(5,055,630.93)	161,296,804.12
Net cash provided (used) by investing activities	(58,245,330.56)	125,772,970.19
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(25,578.45)	(794,155.01)
Net change in short-term debt	-	(174,876,000.00)
Dividends on common stock	(15,000,000.00)	(17,250,000.00)
Net cash provided (used) by financing activities	(15,025,578.45)	(192,920,155.01)
Net Increase (Decrease) in Cash and Cash Equivalents	29,329,912.15	26,232,286.41
Cash and Cash Equivalents at Beginning of Period	24,953,548.52	2,126,011.84
Cash and Cash Equivalents at End of Period	$ 54,283,460.67	$ 28,358,298.25

April 26, 2012

Louisville Gas and Electric 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						
Jefferson County 2000 Series A due 05/01/27 5.375%.......................	$ 17,484.43	$ 111,979.18	$ 53,624.02	$ 335,937.54	$ 967,353.18	$ 1,343,749.95
Trimble County 2000 Series A due 08/01/30 Var%............................	7,639.04	22,593.04	15,602.17	80,221.48	126,252.53	379,359.39
Jefferson County 2001 Series A due 09/01/26 Var%..........................	2,138.70	2,520.39	5,096.95	8,414.39	15,745.31	44,762.10
Jefferson County 2001 Series A due 09/01/27 Var%..........................	6,670.08	23,886.99	18,006.14	69,349.32	115,397.25	223,656.19
Jefferson County 2001 Series B due 11/01/27 Var%.........................	12,267.75	28,699.99	35,744.52	77,564.37	230,491.95	371,453.08
Trimble County 2001 Series A due 09/01/26 Var%............................	6,236.35	9,417.81	16,139.36	29,571.93	85,100.31	149,833.58
Trimble County 2001 Series A due 10/01/32 Var%............................	5,236.58	14,088.47	11,976.77	44,219.68	79,891.85	212,278.02
Trimble County 2001 Series B due 11/01/27 Var%............................	12,336.08	26,513.68	35,812.85	75,849.30	230,853.68	369,782.10
Louisville Metro 2003 Series A due 10/01/33 1.900%.......................	202,666.66	202,666.67	607,999.98	531,930.60	2,427,002.61	531,930.60
Louisville Metro 2005 Series A due 02/01/35 5.750%.......................	191,666.66	191,666.67	574,999.98	575,000.01	2,299,999.95	2,299,999.91
Louisville Metro 2007 Series A due 06/01/33 5.625%.......................	145,312.51	145,312.49	435,937.53	435,937.47	1,743,749.94	1,743,749.92
Louisville Metro 2007 Series B due 06/01/33 1.900%........................	55,733.34	55,733.34	165,342.24	146,280.94	667,425.80	146,280.94
Trimble County 2007 Series A due 06/01/33 4.600%.........................	230,000.00	230,000.00	690,000.00	690,000.00	2,760,000.00	2,760,000.00
Interest Rate Swaps..	672,379.47	642,286.83	1,933,653.09	1,864,155.85	7,842,219.15	7,666,100.66
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/15/15 1.625%..	338,541.65	338,541.67	1,015,624.99	1,015,625.01	4,062,499.97	1,523,437.52
First Mortgage Bond due 11/15/40 5.125%..	1,217,187.51	1,217,187.50	3,651,562.53	3,651,562.50	14,606,250.03	5,477,343.75
Fidelia/PPL..	-	-	-	-	-	16,660,125.02
Revolving Credit Agreement...	-	-	-	185,005.01	-	779,683.35
Total..	3,123,496.81	3,263,094.72	9,267,123.12	9,816,625.40	38,260,233.51	42,683,526.08
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense...	159,869.76	174,306.87	479,609.28	520,320.46	2,057,415.27	927,140.45
Amortization of Loss on Reacquired Debt..	102,453.13	101,002.97	307,351.81	303,008.91	1,217,689.68	1,211,759.13
Total..	262,322.89	275,309.84	786,961.09	823,329.37	3,275,104.95	2,138,899.58
Other Interest Charges						
Customers' Deposits...	115,220.20	111,521.09	337,709.78	320,762.44	1,400,582.33	1,368,240.47
Other Tax Deficiencies..	65,624.01	-	65,624.01	-	79,624.01	(17,500.00)
Interest on DSM Cost Recovery..	(1,109.63)	(1,128.71)	(10,855.93)	1,182.54	3,059.05	11,958.12
Interest on Debt to Associated Companies..	1,102.30	59.44	1,197.13	8,862.00	1,998.22	207,415.04
Other Interest Expense...	85,595.19	46,035.81	253,770.00	130,126.35	1,239,732.65	945,455.69
Total..	266,432.07	156,487.63	647,444.99	460,933.33	2,724,996.26	2,515,569.32
Total Interest..	$ 3,652,251.77	$ 3,694,892.19	$ 10,701,529.20	$ 11,100,888.10	$ 44,260,334.72	$ 47,337,994.98

April 26, 2012

Louisville Gas and Electric 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	$ 1,545,658.00	$ 1,449,790.00	$ 4,636,974.00	$ 4,349,370.00
Unemployment	9,918.99	7,749.12	159,661.15	98,627.46
FICA	648,680.57	731,887.96	2,004,579.35	1,980,045.10
Public Service Commission Fee	162,886.60	161,096.90	488,659.80	483,290.70
Federal Income	(12,307,098.86)	(10,334,822.63)	(2,200,973.02)	6,012,136.68
State Income	(621,707.01)	173,062.26	1,222,084.95	3,154,270.64
Miscellaneous	2,696.30	8,886.80	9,224.44	16,109.47
Total Charged to Operating Expense	(10,558,965.41)	(7,802,349.59)	6,320,210.67	16,093,850.05
Taxes Charged to Other Accounts	3,218,048.74	(155,990.98)	(946,858.49)	819,326.34
Taxes Accrued on Intercompany Accounts	(38,606.57)	(332,255.17)	(113,546.01)	(865,293.26)
Total Taxes Charged	$ (7,379,523.24)	$ (8,290,595.74)	$ 5,259,806.17	$ 16,047,883.13

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	$ 11,998,424.82	$ 4,680,651.00	$ 157,756.05	$ 16,521,319.77
Unemployment	53,328.91	140,084.56	23,296.72	170,116.75
FICA	526,035.87	1,638,093.90	1,822,441.32	341,688.45
Federal Income	-	(2,834,025.00)	(2,834,025.00)	-
State Income	-	-	-	-
Kentucky Sales and Use Tax	671,793.23	1,648,609.81	1,491,463.61	828,939.43
Miscellaneous	35,266.73	(13,608.10)	9,722.73	11,935.90
Totals	$ 13,284,849.56	$ 5,259,806.17	$ 670,655.43	$ 17,874,000.30

April 26, 2012

Louisville Gas and Electric Company
Summary of Utility Plant
March 31, 2012

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant In Service**						
Common						
Common General Plant	$ 157,057,082.39	$ 3,159,995.05	$ (243,220.98)	$ -	$ 2,916,774.07	$ 159,973,856.46
Common Intangible Plant	60,891,162.83	466,307.98	(1,193,940.58)	-	(727,632.60)	60,163,530.23
	217,948,245.22	3,626,303.03	(1,437,161.56)	-	2,189,141.47	220,137,386.69
Electric						
Electric Distribution	964,513,175.85	20,217,722.08	(1,798,292.86)	21,903.14	18,441,332.36	982,954,508.21
Electric General Plant	15,943,111.49	179,252.16	(39,209.64)	-	140,042.52	16,083,154.01
Electric Hydro Production	42,535,934.10	16,456.36	(507.91)	-	15,948.45	42,551,882.55
Electric Intangible Plant	2,240.29	-	-	-	-	2,240.29
Electric Other Production	234,246,978.99	3,514,154.86	(676,874.51)	-	2,837,280.35	237,084,259.34
Electric Steam Production	2,114,510,864.74	16,873,452.22	(1,086,699.39)	-	15,786,752.83	2,130,297,617.57
Electric Transmission	254,611,190.87	5,667,284.03	(1,623,977.77)	-	4,043,306.26	258,654,497.13
	3,626,363,496.33	46,468,321.71	(5,225,562.08)	21,903.14	41,264,662.77	3,667,628,159.10
Gas						
Gas Distribution	592,951,320.42	2,789,364.71	(23,617.80)	(134,900.23)	2,630,846.68	595,582,167.10
Gas General Plant	8,204,172.47	597,531.64	-	-	597,531.64	8,801,704.11
Gas Intangible Plant	387.49	-	-	-	-	387.49
Gas Storage	80,580,078.39	628,184.18	(58,529.30)	-	569,654.88	81,149,733.27
Gas Transmission	21,541,957.36	882,947.47	(1,389.93)	134,900.23	1,016,457.77	22,558,415.13
	703,277,916.13	4,898,028.00	(83,537.03)	-	4,814,490.97	708,092,407.10
Total 101 Accounts	4,547,589,657.68	54,992,652.74	(6,746,260.67)	21,903.14	48,268,295.21	4,595,857,952.89
105 **Plant Held For Future Use**						
Electric						
Electric Distribution	649,014.48	-	-	(21,926.88)	(21,926.88)	627,087.60
Electric Steam Production	-	-	-	-	-	-
	649,014.48	-	-	(21,926.88)	(21,926.88)	627,087.60
Total 105001	$ 649,014.48	$ -	$ -	$ (21,926.88)	$ (21,926.88)	$ 627,087.60

April 26, 2012

Louisville Gas and Electric Company
Summary of Utility Plant
March 31, 2012

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
106 **Completed Construction Not Classified**						
Common						
Common General Plant..	$ 2,574,936.01	$ (1,350,975.02)	$ -	$ -	$ (1,350,975.02)	$ 1,223,960.99
Common Intangible Plant......................................	2,240,884.26	4,066,684.07	-	-	4,066,684.07	6,307,568.33
	4,815,820.27	2,715,709.05	-	-	2,715,709.05	7,531,529.32
Electric						
Electric Distribution...	23,212,235.54	11,845,832.11	-	-	11,845,832.11	35,058,067.65
Electric General Plant..	6,763.22	63,825.04	-	-	63,825.04	70,588.26
Electric Hydro Production.....................................	16,456.36	(16,456.36)	-	-	(16,456.36)	-
Electric Intangible Plant...	-	-	-	-	-	-
Electric Other Production......................................	3,535,959.74	(2,930,744.84)	-	-	(2,930,744.84)	605,214.90
Electric Steam Production......................................	41,241,674.58	(11,287,613.22)	-	-	(11,287,613.22)	29,954,061.36
Electric Transmission...	37,708,783.02	1,552,225.93	-	-	1,552,225.93	39,261,008.95
	105,721,872.46	(772,931.34)	-	-	(772,931.34)	104,948,941.12
Gas						
Gas Distribution...	18,865,984.48	12,074,422.71	-	-	12,074,422.71	30,940,407.19
Gas General Plant..	263,073.78	(84,556.91)	-	-	(84,556.91)	178,516.87
Gas Intangible Plant...	-	-	-	-	-	-
Gas Storage..	514,613.00	6,294,293.16	-	-	6,294,293.16	6,808,906.16
Gas Transmission...	1,459,528.03	(916,290.49)	-	-	(916,290.49)	543,237.54
	21,103,199.29	17,367,868.47	-	-	17,367,868.47	38,471,067.76
Total 106 Accounts	131,640,892.02	19,310,646.18	-	-	19,310,646.18	150,951,538.20
117 **Gas Stored Underground-Noncurrent**						
Gas						
Gas Stored Nonrecoverable...................................	2,139,990.00	-	-	-	-	2,139,990.00
	2,139,990.00	-	-	-	-	2,139,990.00
Total 117001	2,139,990.00	-	-	-	-	2,139,990.00
121 **Nonutility Property**						
Common						
Non Utility Property..	75,239.56	-	-	-	-	75,239.56
	75,239.56	-	-	-	-	75,239.56
Total 121001	75,239.56	-	-	-	-	75,239.56
107 **Construction Work In Progress**						
Common..	15,083,939.33	(4,281,425.55)	-	-	(4,281,425.55)	10,802,513.78
Electric..	152,710,828.07	(15,568,539.20)	-	-	(15,568,539.20)	137,142,288.87
Gas..	47,481,609.94	(11,297,193.25)	-	-	(11,297,193.25)	36,184,416.69
	215,276,377.34	(31,147,158.00)	-	-	(31,147,158.00)	184,129,219.34
Total Plant (Non-CWIP)………………………………	4,682,094,793.74	74,303,298.92	(6,746,260.67)	(23.74)	67,557,014.51	4,749,651,808.25
Total Plant + CWIP………………………………………	4,897,371,171.08	43,156,140.92	(6,746,260.67)	(23.74)	36,409,856.51	4,933,781,027.59
Total Plant + CWIP - Non Utility…………………………	$ 4,897,295,931.52	$ 43,156,140.92	$ (6,746,260.67)	$ (23.74)	$ 36,409,856.51	$ 4,933,705,788.03

April 26, 2012

Louisville Gas and Electric 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										
Common General Plant	$ (77,087,119.39)	$ (3,031,758.62)	$ 243,220.98	$ -	$ -	$ -	$ -	$ -	$ -	$ (79,875,657.03)
Common General Plant - ARO	(2,403.59)	(515.10)	-	-	-	-	-	-	-	(2,918.69)
Electric Distribution	(287,667,187.72)	(4,544,838.48)	1,798,292.86	-	-	-	-	-	-	(290,413,733.34)
Electric Distribution - ARO	(7,290.40)	(2,849.78)	-	(223.56)	-	-	-	-	-	(10,363.74)
Electric General Plant	(11,305,192.13)	(138,484.76)	39,209.64	-	-	-	-	-	-	(11,404,467.25)
Electric Hydro Production	(10,051,997.22)	(141,469.07)	507.91	-	-	-	-	-	-	(10,192,958.38)
Electric Hydro Production - ARO	(2,112.62)	(437.13)	-	-	-	-	-	-	-	(2,549.75)
Electric Other Production	(67,466,740.67)	(2,095,352.80)	676,874.51	-	-	-	-	-	-	(68,885,218.96)
Electric Other Production - ARO	(1,302.82)	(289.68)	-	-	-	-	-	-	-	(1,592.50)
Electric Steam Production	(1,060,614,162.86)	(14,361,072.62)	1,086,699.39	-	-	-	-	-	-	(1,073,888,536.09)
Electric Steam Production - ARO	(1,402,047.92)	(448,236.05)	-	-	-	-	-	-	-	(1,850,283.97)
Electric Transmission	(121,989,304.84)	(1,131,896.19)	1,623,977.77	-	-	-	-	-	-	(121,497,223.26)
Electric Transmission - ARO	(903.28)	(2,038.83)	-	-	-	-	-	-	-	(2,942.11)
Gas Distribution	(131,835,425.42)	(3,045,800.28)	23,617.80	1,037.44	-	-	-	-	-	(134,856,570.46)
Gas Distribution - ARO	(346,237.51)	(74,185.93)	-	-	-	-	-	-	-	(420,423.44)
Gas General Plant	(5,044,235.87)	(93,208.87)	-	-	-	-	-	-	-	(5,137,444.74)
Gas Storage	(31,071,784.79)	(304,911.96)	58,529.30	-	-	-	-	-	-	(31,318,167.45)
Gas Storage - ARO	(257,551.24)	(55,045.34)	-	-	-	-	-	-	-	(312,596.58)
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(9,486,356.38)	(15,224.29)	1,389.93	(1,037.44)	-	-	-	-	-	(9,501,228.18)
Gas Transmission - ARO	(35,270.86)	(26,453.13)	-	-	-	-	-	-	-	(61,723.99)
Non Utility Property	(63,360.36)	-	-	-	-	-	-	-	-	(63,360.36)
	(1,815,737,987.89)	(29,514,068.91)	5,552,320.09	(223.56)	-	-	-	-	-	(1,839,699,960.27)
Cost Of Removal										
Common General Plant	(637,762.44)	(72,227.92)	-	-	-	-	16,557.84	-	-	(693,432.52)
Electric Distribution	(148,949,763.17)	(1,805,735.27)	-	-	-	-	2,613,761.99	-	-	(148,141,736.45)
Electric General Plant	3,866.64	-	-	-	-	-	-	-	-	3,866.64
Electric Hydro Production	732,455.11	(10,738.08)	-	-	-	-	1,017.40	-	-	722,734.43
Electric Other Production	(2,535,958.71)	(89,811.36)	-	-	-	-	170,979.16	-	-	(2,454,790.91)
Electric Steam Production	(108,291,391.50)	(4,302,848.84)	-	-	-	-	1,387,859.46	-	-	(111,206,380.88)
Electric Transmission	(25,759,724.87)	(362,863.86)	-	-	-	-	404,164.79	-	-	(25,718,423.94)
Gas Distribution	(62,001,399.83)	(858,648.41)	-	300.39	-	-	60,363.73	-	-	(62,799,384.12)
Gas General Plant	(0.02)	-	-	-	-	-	-	-	-	(0.02)
Gas Storage	262,470.54	(39,237.25)	-	-	-	-	-	-	-	223,233.29
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(2,984,857.77)	(3,768.83)	-	(300.39)	-	-	21,090.05	-	-	(2,967,836.94)
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	$ (350,162,066.02)	$ (7,545,879.82)	$ -	$ -	$ -	$ -	$ 4,675,794.42	$ -	$ -	$ (353,032,151.42)

April 26, 2012

Louisville Gas and Electric 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
Salvage										
Common General Plant	$ 278,457.83	$ 95.82	$ -	$ -	$ -	$ -	$ -	$ (3,000.00)	$ -	$ 275,553.65
Electric Distribution	18,531,222.48	368,163.38	-	-	-	-	-	(54,967.23)	-	18,844,418.63
Electric General Plant	140,589.22	596.79	-	-	-	-	-	-	-	141,186.01
Electric Hydro Production	376,638.17	-	-	-	-	-	-	-	-	376,638.17
Electric Other Production	(18,998.67)	-	-	-	-	-	-	-	-	(18,998.67)
Electric Steam Production	24,020,678.65	512,183.75	-	-	-	-	-	(126,226.16)	-	24,406,636.24
Electric Transmission	6,511,015.77	66,958.76	-	-	-	-	-	(357,106.44)	-	6,220,868.09
Gas Distribution	3,791,455.11	51,510.74	-	-	-	-	-	-	-	3,842,965.85
Gas General Plant	228,159.61	727.46	-	-	-	-	-	-	-	228,887.07
Gas Storage	287,152.21	4,482.28	-	-	-	-	-	-	-	291,634.49
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	223,309.53	1,413.32	-	-	-	-	-	-	-	224,722.85
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	54,369,679.91	1,006,132.30	-	-	-	-	-	(541,299.83)	-	54,834,512.38
Total Reserves										
Common	(77,512,187.95)	(3,104,405.82)	243,220.98	-	-	-	16,557.84	(3,000.00)	-	(80,359,814.95)
Electric	(1,795,747,613.36)	(28,491,060.12)	5,225,562.08	(223.56)	-	-	4,577,782.80	(538,299.83)	-	(1,814,973,851.99)
Gas	(238,270,572.69)	(4,458,350.49)	83,537.03	-	-	-	81,453.78	-	-	(242,563,932.37)
	(2,111,530,374.00)	(36,053,816.43)	5,552,320.09	(223.56)	-	-	4,675,794.42	(541,299.83)	-	(2,137,897,599.31)
Retirement Work In Progress										
Common	149,762.35	-	-	-	-	(13,557.84)	(17,161.19)	(10,496.95)	-	108,546.37
Electric	11,924,715.03	-	-	(14,615.87)	-	(4,039,482.97)	5,226,585.53	(301,510.06)	(83,094.73)	12,712,596.93
Gas	1,590,687.78	-	-	14,615.87	-	(81,453.78)	284,819.85	(1,181.09)	-	1,807,488.63
	13,665,165.16	-	-	-	-	(4,134,494.59)	5,494,244.19	(313,188.10)	(83,094.73)	14,628,631.93
YTD ACTIVITY	(2,097,865,208.84)	(36,053,816.43)	5,552,320.09	(223.56)	-	(4,134,494.59)	10,170,038.61	(854,487.93)	(83,094.73)	(2,123,268,967.38)
Amortization										
Common	(20,071,604.03)	(2,177,175.30)	1,193,940.58	-	-	-	-	-	-	(21,054,838.75)
Electric	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-
AMORTIZATION TOTAL	(20,071,604.03)	(2,177,175.30)	1,193,940.58	-	-	-	-	-	-	(21,054,838.75)
Depreciation & Amortization Total	$ (2,117,936,812.87)	$ (38,230,991.73)	$ 6,746,260.67	$ (223.56)	$ -	$ (4,134,494.59)	$ 10,170,038.61	$ (854,487.93)	$ (83,094.73)	$ (2,144,323,806.13)
Depr & Amort - Nonutility for Balance Sheet										(2,144,260,445.77)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)	$ 2,779,422,479.01									$ 2,789,445,342.26

April 26, 2012

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
March 31, 2012

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues.......................................	$ 80,159,282.52	$ -	$ 80,159,282.52
Gas Operating Revenues...	23,666,489.53	-	23,666,489.53
Total Operating Revenues..	103,825,772.05	-	103,825,772.05
Fuel for Electric Generation..	29,806,959.77	-	29,806,959.77
Power Purchased...	4,707,080.96	-	4,707,080.96
Gas Supply Expenses..	8,869,275.78	-	8,869,275.78
Other Operation Expenses...	20,103,047.79	-	20,103,047.79
Maintenance..	12,050,118.95	-	12,050,118.95
Depreciation..	12,009,763.52	-	12,009,763.52
Amortization Expense...	736,955.24	-	736,955.24
Regulatory Credits...	(446,222.39)	-	(446,222.39)
Taxes			
Federal Income...	(12,307,098.86)	-	(12,307,098.86)
State Income..	(621,707.01)	-	(621,707.01)
Deferred Federal Income - Net.................................	15,059,088.67	8,230.82	15,067,319.49
Deferred State Income - Net.....................................	847,565.83	1,501.05	849,066.88
Property and Other...	2,369,840.46	-	2,369,840.46
Amortization of Investment Tax Credit....................	(223,357.47)	-	(223,357.47)
Loss (Gain) from Disposition of Allowances...............	(693.97)	-	(693.97)
Accretion Expense..	242,872.24	-	242,872.24
Total Operating Expenses..	93,203,489.51	9,731.87	93,213,221.38
Net Operating Income...	10,622,282.54	(9,731.87)	10,612,550.67
Other Income Less Deductions.................................	(554,124.33)	-	(554,124.33)
Income Before Interest Charges................................	10,068,158.21	(9,731.87)	10,058,426.34
Interest on Long-Term Debt..	3,123,496.81	(25,017.63)	3,098,479.18
Amortization of Debt Expense - Net...........................	262,322.89	-	262,322.89
Other Interest Expenses...	266,432.07	-	266,432.07
Total Interest Charges..	3,652,251.77	(25,017.63)	3,627,234.14
Net Income..	$ 6,415,906.44	$ 15,285.76	$ 6,431,192.20

April 26, 2012

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
March 31, 2012

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 244,420,426.43	$ -	$ 244,420,426.43
Gas Operating Revenues	108,809,879.08	-	108,809,879.08
Total Operating Revenues	353,230,305.51	-	353,230,305.51
Fuel for Electric Generation	91,719,151.25	-	91,719,151.25
Power Purchased	13,783,932.99	-	13,783,932.99
Gas Supply Expenses	57,345,602.29	-	57,345,602.29
Other Operation Expenses	58,884,895.86	-	58,884,895.86
Maintenance	35,586,242.09	-	35,586,242.09
Depreciation	35,897,362.32	-	35,897,362.32
Amortization Expense	2,177,175.30	-	2,177,175.30
Regulatory Credits	(1,335,588.73)	-	(1,335,588.73)
Taxes			
Federal Income	(2,200,973.02)	-	(2,200,973.02)
State Income	1,222,084.95	-	1,222,084.95
Deferred Federal Income - Net	15,135,238.66	24,692.42	15,159,931.08
Deferred State Income - Net	847,565.83	4,503.17	852,069.00
Property and Other	7,299,098.74	-	7,299,098.74
Amortization of Investment Tax Credit	(670,069.47)	-	(670,069.47)
Loss (Gain) from Disposition of Allowances	(693.97)	-	(693.97)
Accretion Expense	725,537.76	-	725,537.76
Total Operating Expenses	316,416,562.85	29,195.59	316,445,758.44
Net Operating Income	36,813,742.66	(29,195.59)	36,784,547.07
Other Income Less Deductions	(923,118.22)	-	(923,118.22)
Income Before Interest Charges	35,890,624.44	(29,195.59)	35,861,428.85
Interest on Long-Term Debt	9,267,123.12	(75,052.89)	9,192,070.23
Amortization of Debt Expense - Net	786,961.09	-	786,961.09
Other Interest Expenses	647,444.99	-	647,444.99
Total Interest Charges	10,701,529.20	(75,052.89)	10,626,476.31
Net Income	$ 25,189,095.24	$ 45,857.30	$ 25,234,952.54

April 26, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
March 31, 2012

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period…………………………	$ 872,702,746.19	$ 842,546,810.76	$ (808,702,319.19)	$ (808,163,552.92)	$ 64,000,427.00	$ 34,383,257.84
Add:						
Net Income (Loss) for Period………………………	6,415,906.44	7,291,888.99	15,285.76	(706,873.76)	6,431,192.20	6,585,015.23
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	-	-	-	-	-	-
Balance at End of Period…………………………………	$ 879,118,652.63	$ 849,838,699.75	$ (808,687,033.43)	$ (808,870,426.68)	$ 70,431,619.20	$ 40,968,273.07

April 26, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
March 31, 2012

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……	$ 868,929,557.39	$ 827,993,251.96	$ (808,732,890.73)	$ (808,899,282.44)	$ 60,196,666.66	$ 19,093,969.52
Add:						
Net Income (Loss) for Period……	25,189,095.24	39,095,447.79	45,857.30	28,855.76	25,234,952.54	39,124,303.55
Deduct:						
Adjustment to Retained Earnings……	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value……	15,000,000.00	17,250,000.00	-	-	15,000,000.00	17,250,000.00
Balance at End of Period……	$ 879,118,652.63	$ 849,838,699.75	$ (808,687,033.43)	$ (808,870,426.68)	$ 70,431,619.20	$ 40,968,273.07

April 26, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
March 31, 2012

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……	$ 849,838,699.75	$ 757,728,567.29	$ (808,870,426.68)	$ -	$ 40,968,273.07	$ 757,728,567.29
Add:						
Net Income (Loss) for Period……	110,279,952.88	134,360,132.46	183,393.25	76,464.84	110,463,346.13	134,436,597.30
Deduct:						
Adjustment to Retained Earnings……	-	-	-	808,946,891.52	-	808,946,891.52
Common Dividends						
Common Stock Without Par Value……	81,000,000.00	42,250,000.00	-	-	81,000,000.00	42,250,000.00
Balance at End of Period……	$ 879,118,652.63	$ 849,838,699.75	$ (808,687,033.43)	$ (808,870,426.68)	$ 70,431,619.20	$ 40,968,273.07

April 26, 2012

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of March 31, 2012

Assets	Without Purchase Accounting	Purchase Accounting	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 4,933,705,788.03	$ -	$ 4,933,705,788.03
Less: Reserves for Depreciation and Amortization....	2,144,260,445.77	-	2,144,260,445.77
Total..	2,789,445,342.26	-	2,789,445,342.26
Investments			
Ohio Valley Electric Corporation.............................	594,286.00	-	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	-	11,879.20
Special Funds...	26,812,546.91	-	26,812,546.91
Total..	27,418,712.11	-	27,418,712.11
Current and Accrued Assets			
Cash..	37,944,606.65	-	37,944,606.65
Special Deposits..	-	-	-
Temporary Cash Investments...................................	16,338,854.02	-	16,338,854.02
Accounts Receivable - Less Reserve.........................	121,482,082.46	-	121,482,082.46
Accounts Receivable from Associated Companies....	20,097,723.37	-	20,097,723.37
Materials and Supplies - At Average Cost			
Fuel..	66,393,015.44	-	66,393,015.44
Plant Materials and Operating Supplies.................	30,964,056.64	-	30,964,056.64
Stores Expense...	5,553,099.47	-	5,553,099.47
Gas Stored Underground.......................................	20,184,889.10	-	20,184,889.10
Emission Allowances...	17,221.12	-	17,221.12
Prepayments..	4,804,662.67	-	4,804,662.67
Miscellaneous Current and Accrued Assets..............	693.97	-	693.97
Total..	323,780,904.91	-	323,780,904.91
Deferred Debits and Other			
Unamortized Debt Expense......................................	12,916,551.41	(3,434,540.22)	9,482,011.19
Unamortized Loss on Bonds....................................	20,682,089.39	-	20,682,089.39
Accumulated Deferred Income Taxes.......................	22,116,906.94	64,512,535.21	86,629,442.15
Deferred Regulatory Assets.....................................	388,800,142.12	8,109,432.61	396,909,574.73
Other Deferred Debits..	1,804,929.40	155,015,683.08	156,820,612.48
Goodwill..	-	389,157,351.59	389,157,351.59
Total..	446,320,619.26	613,360,462.27	1,059,681,081.53
Total Assets..	$ 3,586,965,578.54	$ 613,360,462.27	$ 4,200,326,040.81

April 26, 2012

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of March 31, 2012

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting	Total
Proprietary Capital			
Common Stock...	$ 425,170,424.09	$ -	$ 425,170,424.09
Less: Common Stock Expense......................................	835,888.64	-	835,888.64
Paid-In Capital...	83,581,499.00	1,194,085,869.02	1,277,667,368.02
Other Comprehensive Income.......................................	-	-	-
Retained Earnings..	879,118,652.63	(808,687,033.43)	70,431,619.20
Total Proprietary Capital...	1,387,034,687.08	385,398,835.59	1,772,433,522.67
Pollution Control Bonds - Net of Reacquired Bonds.....	574,304,000.00	6,151,417.29	580,455,417.29
First Mortgage Bonds..	531,401,507.42	-	531,401,507.42
LT Notes Payable to Associated Companies................	-	-	-
Total Long-Term Debt...	1,105,705,507.42	6,151,417.29	1,111,856,924.71
Total Capitalization...	2,492,740,194.50	391,550,252.88	2,884,290,447.38
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies.................	-	-	-
Accounts Payable...	92,234,601.80	-	92,234,601.80
Accounts Payable to Associated Companies................	15,938,027.00	-	15,938,027.00
Customer Deposits...	22,435,650.26	-	22,435,650.26
Taxes Accrued...	17,874,000.30	-	17,874,000.30
Interest Accrued...	12,083,404.23	-	12,083,404.23
Miscellaneous Current and Accrued Liabilities............	28,854,345.46	-	28,854,345.46
Total..	189,420,029.05	-	189,420,029.05
Deferred Credits and Other			
Accumulated Deferred Income Taxes...........................	515,319,247.11	62,119,633.92	577,438,881.03
Investment Tax Credit...	42,048,774.66	-	42,048,774.66
Regulatory Liabilities...	58,003,499.13	155,015,683.08	213,019,182.21
Customer Advances for Construction...........................	7,329,863.59	-	7,329,863.59
Asset Retirement Obligations..	59,331,864.27	-	59,331,864.27
Other Deferred Credits..	8,148,016.44	4,674,892.39	12,822,908.83
Miscellaneous Long-Term Liabilities...........................	53,954,916.00	-	53,954,916.00
Misc Long-Term Liab Due to Assoc Cos......................	-	-	-
Accum Provision for Postretirement Benefits................	160,669,173.79	-	160,669,173.79
Total..	904,805,354.99	221,810,209.39	1,126,615,564.38
Total Liabilities and Stockholders' Equity..........................	$ 3,586,965,578.54	$ 613,360,462.27	$ 4,200,326,040.81

April 26, 2012

LOUISVILLE GAS AND ELECTRIC COMPANY

Financial Reports

February 29, 2012

Index
Financial and Operating Reports

Louisville Gas and Electric 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.

Louisville Gas and Electric Company
Comparative Statement of Income
February 29, 2012

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 76,140,406.22	$ 81,391,948.43	$ (5,251,542.21)	(6.45)
Gas Operating Revenues	37,643,413.75	44,131,163.97	(6,487,750.22)	(14.70)
Total Operating Revenues	113,783,819.97	125,523,112.40	(11,739,292.43)	(9.35)
Fuel for Electric Generation	28,081,303.76	27,823,577.78	257,725.98	0.93
Power Purchased	3,787,880.17	6,044,560.87	(2,256,680.70)	(37.33)
Gas Supply Expenses	20,484,139.27	27,043,442.47	(6,559,303.20)	(24.25)
Other Operation Expenses	18,991,439.19	19,230,023.55	(238,584.36)	(1.24)
Maintenance	15,573,622.75	7,878,568.47	7,695,054.28	97.67
Depreciation	11,967,373.42	11,598,433.49	368,939.93	3.18
Amortization Expense	734,402.48	641,818.81	92,583.67	14.43
Regulatory Credits	(438,995.64)	(367,551.24)	(71,444.40)	(19.44)
Taxes				
Federal Income	2,800,341.89	6,404,946.04	(3,604,604.15)	(56.28)
State Income	510,700.66	1,168,075.26	(657,374.60)	(56.28)
Deferred Federal Income - Net	-	-	-	-
Deferred State Income - Net	-	-	-	-
Property and Other	2,307,156.00	2,263,528.10	43,627.90	1.93
Amortization of Investment Tax Credit	(223,356.00)	(236,034.00)	12,678.00	5.37
Loss (Gain) from Disposition of Allowances	-	-	-	-
Accretion Expense	241,844.43	219,602.14	22,242.29	10.13
Total Operating Expenses	104,817,852.38	109,712,991.74	(4,895,139.36)	(4.46)
Net Operating Income	8,965,967.59	15,810,120.66	(6,844,153.07)	(43.29)
Other Income Less Deductions	(204,264.82)	760,189.16	(964,453.98)	(126.87)
Income Before Interest Charges	8,761,702.77	16,570,309.82	(7,808,607.05)	(47.12)
Interest on Long-Term Debt	3,093,107.19	3,257,472.39	(164,365.20)	(5.05)
Amortization of Debt Expense - Net	262,322.89	274,350.15	(12,027.26)	(4.38)
Other Interest Expenses	195,170.90	147,100.30	48,070.60	32.68
Total Interest Charges	3,550,600.98	3,678,922.84	(128,321.86)	(3.49)
Net Income	$ 5,211,101.79	$ 12,891,386.98	$ (7,680,285.19)	(59.58)

March 21, 2012

Louisville Gas and Electric Company
Comparative Statement of Income
February 29, 2012

	Year to Date			
	This Year	Last Year	Increase or Decrease	
	Amount	Amount	Amount	%
Electric Operating Revenues..	$ 164,261,143.91	$ 173,488,682.96	$ (9,227,539.05)	(5.32)
Gas Operating Revenues..	85,143,389.55	102,945,174.64	(17,801,785.09)	(17.29)
Total Operating Revenues..	249,404,533.46	276,433,857.60	(27,029,324.14)	(9.78)
Fuel for Electric Generation...	61,912,191.48	60,141,089.93	1,771,101.55	2.94
Power Purchased...	9,076,852.03	13,119,314.25	(4,042,462.22)	(30.81)
Gas Supply Expenses..	48,476,326.51	65,350,875.94	(16,874,549.43)	(25.82)
Other Operation Expenses...	38,781,848.07	37,656,179.11	1,125,668.96	2.99
Maintenance..	23,536,123.14	14,643,464.39	8,892,658.75	60.73
Depreciation..	23,887,598.80	22,875,634.84	1,011,963.96	4.42
Amortization Expense...	1,440,220.06	1,281,835.11	158,384.95	12.36
Regulatory Credits...	(889,366.34)	(734,163.07)	(155,203.27)	(21.14)
Taxes				
Federal Income..	10,106,125.84	16,346,959.31	(6,240,833.47)	(38.18)
State Income...	1,843,791.96	2,981,208.38	(1,137,416.42)	(38.15)
Deferred Federal Income - Net....................................	76,149.99	6.82	76,143.17	1,116,468.77
Deferred State Income - Net.......................................	-	-	-	-
Property and Other..	4,929,258.28	4,568,031.95	361,226.33	7.91
Amortization of Investment Tax Credit......................	(446,712.00)	(445,401.00)	(1,311.00)	(0.29)
Loss (Gain) from Disposition of Allowances...............	-	-	-	-
Accretion Expense..	482,665.52	438,264.78	44,400.74	10.13
Total Operating Expenses..	223,213,073.34	238,223,300.74	(15,010,227.40)	(6.30)
Net Operating Income..	26,191,460.12	38,210,556.86	(12,019,096.74)	(31.45)
Other Income Less Deductions..................................	(368,993.89)	998,997.85	(1,367,991.74)	(136.94)
Income Before Interest Charges.................................	25,822,466.23	39,209,554.71	(13,387,088.48)	(34.14)
Interest on Long-Term Debt..	6,143,626.31	6,553,530.68	(409,904.37)	(6.25)
Amortization of Debt Expense - Net.............................	524,638.20	548,019.53	(23,381.33)	(4.27)
Other Interest Expenses...	381,012.92	304,445.70	76,567.22	25.15
Total Interest Charges..	7,049,277.43	7,405,995.91	(356,718.48)	(4.82)
Net Income..	$ 18,773,188.80	$ 31,803,558.80	$ (13,030,370.00)	(40.97)

March 21, 2012

Louisville Gas and Electric 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	$ 1,050,522,764.44	$ 1,022,971,893.88	$ 27,550,870.56	2.69
Gas Operating Revenues	286,772,636.73	300,980,111.84	(14,207,475.11)	(4.72)
Total Operating Revenues	1,337,295,401.17	1,323,952,005.72	13,343,395.45	1.01
Fuel for Electric Generation	362,739,494.91	370,971,646.94	(8,232,152.03)	(2.22)
Power Purchased	70,852,084.90	55,123,886.26	15,728,198.64	28.53
Gas Supply Expenses	144,361,076.27	173,172,189.92	(28,811,113.65)	(16.64)
Other Operation Expenses	237,403,023.85	227,153,736.21	10,249,287.64	4.51
Maintenance	125,251,727.30	113,725,742.92	11,525,984.38	10.13
Depreciation	143,010,178.88	132,522,697.73	10,487,481.15	7.91
Amortization Expense	8,291,848.98	7,550,526.75	741,322.23	9.82
Regulatory Credits	(5,885,288.96)	(4,644,664.96)	(1,240,624.00)	(26.71)
Taxes				
Federal Income	5,722,016.98	26,909,253.25	(21,187,236.27)	(78.74)
State Income	7,128,116.25	5,730,730.86	1,397,385.39	24.38
Deferred Federal Income - Net	52,299,867.53	27,897,238.72	24,402,628.81	87.47
Deferred State Income - Net	2,011,675.35	2,370,024.44	(358,349.09)	(15.12)
Property and Other	28,482,809.97	23,035,187.94	5,447,622.03	23.65
Amortization of Investment Tax Credit	(2,807,043.00)	(2,530,211.00)	(276,832.00)	(10.94)
Loss (Gain) from Disposition of Allowances	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense	2,688,885.36	3,392,420.38	(703,535.02)	(20.74)
Total Operating Expenses	1,181,547,896.63	1,162,345,946.22	19,201,950.41	1.65
Net Operating Income	155,747,504.54	161,606,059.50	(5,858,554.96)	(3.63)
Other Income Less Deductions	(288,593.97)	11,893,952.62	(12,182,546.59)	(102.43)
Income Before Interest Charges	155,458,910.57	173,500,012.12	(18,041,101.55)	(10.40)
Interest on Long-Term Debt	38,399,831.42	43,263,247.09	(4,863,415.67)	(11.24)
Amortization of Debt Expense - Net	3,288,091.90	1,979,972.76	1,308,119.14	66.07
Other Interest Expenses	2,615,051.82	2,559,808.75	55,243.07	2.16
Total Interest Charges	44,302,975.14	47,803,028.60	(3,500,053.46)	(7.32)
Net Income	$ 111,155,935.43	$ 125,696,983.52	$ (14,541,048.09)	(11.57)

March 21, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings
February 29, 2012

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period..	$ 882,491,644.40	$ 846,905,423.78	$ 868,929,557.39	$ 827,993,251.96	$ 842,546,810.76	$ 789,099,827.24
Add:						
Net Income for Period..	5,211,101.79	12,891,386.98	18,773,188.80	31,803,558.80	111,155,935.43	125,696,983.52
Deduct:						
Common Dividends						
Common Stock Without Par Value.....................	15,000,000.00	17,250,000.00	15,000,000.00	17,250,000.00	81,000,000.00	72,250,000.00
Balance at End of Period..	$ 872,702,746.19	$ 842,546,810.76	$ 872,702,746.19	$ 842,546,810.76	$ 872,702,746.19	$ 842,546,810.76

March 21, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of February 29, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,919,723,457.68	$ 4,755,964,845.70
Less: Reserves for Depreciation and Amortization	2,137,988,703.28	2,058,736,206.02
Total	2,781,734,754.40	2,697,228,639.68
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	30,310,548.45	15,268,536.90
Total	30,916,713.65	15,874,702.10
Current and Accrued Assets		
Cash	38,370,592.06	16,211,302.24
Special Deposits	-	1,618,654.10
Temporary Cash Investments	16,534,761.64	1,872.19
Accounts Receivable - Less Reserve	129,860,629.76	154,061,012.70
Accounts Receivable from Associated Companies	15,190,151.03	9,427,052.69
Materials and Supplies - At Average Cost		
Fuel	57,383,128.29	66,707,850.08
Plant Materials and Operating Supplies	30,831,292.12	29,621,208.53
Stores Expense	5,538,432.48	5,077,532.37
Gas Stored Underground	27,251,651.60	29,403,684.34
Emission Allowances	18,675.79	2,482.89
Prepayments	5,872,637.42	6,421,800.81
Miscellaneous Current and Accrued Assets	-	1,725,982.95
Total	326,851,952.19	320,280,435.89
Deferred Debits and Other		
Unamortized Debt Expense	13,053,099.47	13,480,018.81
Unamortized Loss on Bonds	20,784,542.53	21,732,643.55
Accumulated Deferred Income Taxes	23,749,922.01	53,869,965.22
Deferred Regulatory Assets	396,075,506.26	353,942,206.87
Other Deferred Debits	1,224,882.41	(99,098.81)
Total	454,887,952.68	442,925,735.64
Total Assets	$ 3,594,391,372.92	$ 3,476,309,513.31

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	872,702,746.19	842,546,810.76
Total Proprietary Capital	1,380,618,780.64	1,350,462,845.21
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,378,185.76	531,098,325.82
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,105,682,185.76	1,105,402,325.82
Total Capitalization	2,486,300,966.40	2,455,865,171.03
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	5,664,000.00
Notes Payable	-	-
Accounts Payable	96,978,222.55	69,841,267.94
Accounts Payable to Associated Companies	13,291,277.31	9,519,697.55
Customer Deposits	22,518,161.40	23,753,770.99
Taxes Accrued	23,830,129.23	21,091,839.71
Dividends Declared	15,000,000.00	17,250,000.00
Interest Accrued	9,522,801.62	9,153,672.60
Miscellaneous Current and Accrued Liabilities	27,524,482.90	28,798,384.87
Total	208,665,075.01	185,072,633.66
Deferred Credits and Other		
Accumulated Deferred Income Taxes	499,655,847.55	473,518,807.92
Investment Tax Credit	42,272,132.13	45,079,175.13
Regulatory Liabilities	59,483,304.96	65,182,295.26
Customer Advances for Construction	7,342,362.81	8,441,333.51
Asset Retirement Obligations	59,088,992.03	53,089,053.69
Other Deferred Credits	10,978,950.12	8,625,923.25
Miscellaneous Long-Term Liabilities	58,881,944.50	33,222,865.65
Accum Provision for Postretirement Benefits	161,721,797.41	148,212,254.21
Total	899,425,331.51	835,371,708.62
Total Liabilities and Stockholders' Equity	$ 3,594,391,372.92	$ 3,476,309,513.31

March 21, 2012

Louisville Gas and Electric 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..........	75,000,000	21,294,223	$ 425,170,424.09	
Less: Common Stock Expense..........			835,888.64	
Paid-In Capital..........			83,581,499.00	
Other Comprehensive Income..........			-	
Retained Earnings..........			872,702,746.19	
Total Proprietary Capital..........			1,380,618,780.64	55.53
Long-Term Debt				
Pollution Control Bonds..........				
Jefferson County 2000 Series A due 05/01/27 5.375%..........			25,000,000.00	
Trimble County 2000 Series A due 08/01/30 Var%..........			83,335,000.00	
Jefferson County 2001 Series A due 09/01/26 Var%..........			22,500,000.00	
Jefferson County 2001 Series A due 09/01/27 Var%..........			10,104,000.00	
Jefferson County 2001 Series B due 11/01/27 Var%..........			35,000,000.00	
Trimble County 2001 Series A due 09/01/26 Var%..........			27,500,000.00	
Trimble County 2001 Series A due 10/01/32 Var%..........			41,665,000.00	
Trimble County 2001 Series B due 11/01/27 Var%..........			35,000,000.00	
Louisville Metro 2003 Series A due 10/01/33 1.900%..........			128,000,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%..........			40,000,000.00	
Louisville Metro 2007 Series A due 06/01/33 5.625%..........			31,000,000.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%..........			35,200,000.00	
Trimble County 2007 Series A due 06/01/33 4.600%..........			60,000,000.00	
Total Pollution Control Bonds..........			574,304,000.00	23.10
First Mortgage Bonds..........				
First Mortgage Bond Due 11/15/15 1.625%..........			250,000,000.00	
First Mortgage Bond Due 11/15/40 5.125%..........			285,000,000.00	
Total First Mortgage Bonds..........			535,000,000.00	21.52
Less: First Mortgage Bonds Debt Discount..........				
First Mortgage Bond Due 11/15/15 1.625%..........			(654,520.87)	
First Mortgage Bond Due 11/15/40 5.125%..........			(2,967,293.37)	
			(3,621,814.24)	(0.15)
Total First Mortgage Bonds - Net of Debt Discount..........			531,378,185.76	21.37
Total Capitalization..........			$ 2,486,300,966.40	100.00

March 21, 2012

Louisville Gas and Electric Company
Summary Trial Balance
February 29, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 4,919,723,457.68	$ 4,919,723,457.68
Reserves for Depreciation and Amortization		(2,137,988,703.28)
Depreciation of Plant		
Electric	(1,797,823,817.23)	
Gas	(239,376,723.87)	
Common	(79,276,338.09)	
Amortization of Plant		
Common	(21,511,824.09)	
Investments		30,916,713.65
Special Funds	30,310,548.45	
Ohio Valley Electric Corporation	594,286.00	
Nonutility Property	11,879.20	
Cash	38,370,592.06	38,370,592.06
Temporary Cash Investments	16,534,761.64	16,534,761.64
Accounts Receivable - Less Reserve		129,860,629.76
Customers - Active	68,438,976.61	
Unbilled Revenues	56,253,749.00	
IMPA	2,086,599.18	
IMEA	2,045,119.68	
Sundry Accounts Receivable	1,054,927.56	
Transmission Sales	526,952.31	
Damage Claims	457,513.18	
Wholesale Sales	342,862.36	
Rents Receivable	235,765.12	
Electricity Swaps	166,354.87	
Bechtel Liquidated Damages	11,400.00	
Officers and Employees	(536.38)	
Other	235,963.61	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	924,933.15	
Reserve	(1,557,498.00)	
Accrual	(671,150.37)	
A/R Miscellaneous	(271,164.47)	
Recoveries	(253,782.78)	
LEM Reserve	(166,354.87)	
Accounts Receivable from Associated Companies		15,190,151.03
LG&E and KU Services/Kentucky Utilities	15,190,135.50	
PPL Energy Funding	15.53	
Fuel		57,383,128.29
Coal 1,104,348.52 Tons @ $51.47; MMBtu 24,784,187.39 @ 229.35¢	56,841,777.37	
Fuel Oil 180,105.01 Gallons @ 266.81¢	480,542.54	
Gas Pipeline 5,100 Mcf @ $11.92	60,808.38	
Plant Materials and Operating Supplies		30,831,292.12
Regular Materials and Supplies	29,960,157.97	
Limestone 95,204.73 Tons @ $9.15	871,134.15	
Stores Expense Undistributed	5,538,432.48	5,538,432.48
Gas Stored Underground - Current		27,251,651.60
Gas Stored Underground* 5,866,721 Mcf (14.73 psia) @ $4.65	27,251,651.60	
Emission Allowances	18,675.79	18,675.79

March 21, 2012

Louisville Gas and Electric Company
Summary Trial Balance
February 29, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Prepayments		$ 5,872,637.42
Insurance	1,825,984.03	
Taxes	651,546.46	
Franchises	361,332.20	
Rights of Way	226,666.71	
Risk Management and Workers Compensation	90,000.00	
Other	2,717,108.02	
Unamortized Debt Expense		13,053,099.47
Trimble County 2000 Series A due 08/01/30 Var%	712,860.82	
Jefferson County 2001 Series A due 09/01/26 Var%	143,894.70	
Jefferson County 2001 Series A due 09/01/27 Var%	316,083.64	
Jefferson County 2001 Series B due 11/01/27 Var%	172,258.92	
Trimble County 2001 Series A due 09/01/26 Var%	156,454.74	
Trimble County 2001 Series B due 11/01/27 Var%	172,287.18	
Trimble County 2002 Series A due 10/01/32 Var%	766,140.77	
Louisville Metro 2003 Series A Due 10/01/33 1.900%	429,217.43	
Louisville Metro 2007 Series B Due 06/01/33 1.900%	164,806.71	
Trimble County 2007 Series A due 06/01/33 4.600%	1,010,106.26	
First Mortgage Bond due 11/15/15 1.625%	1,932,759.56	
First Mortgage Bond due 11/15/40 5.125%	3,422,787.04	
Revolving Credit Agreement	3,653,441.70	
Unamortized Loss on Bonds	20,784,542.53	20,784,542.53
Accumulated Deferred Income Taxes		23,749,922.01
Federal		
Electric	17,577,286.97	
Gas	1,368,281.19	
State		
Electric	4,502,703.92	
Gas	301,649.93	
Regulatory Assets		396,075,506.26
Pension and Postretirement Benefits	225,481,749.00	
Interest Rate Swap Ineffectiveness	57,749,836.68	
2009 Winter Storm	36,897,312.61	
2008 Wind Storm	19,813,113.43	
Deferred Taxes - ASC 740		
Federal		
Electric	12,458,133.70	
State		
Electric	2,272,000.07	
Asset Retirement Obligations		
Electric	10,013,751.86	
Gas	1,531,954.79	
Common	10,443.39	
Swap Termination	8,894,142.46	
2011 Summer Storm	8,052,124.65	
Fuel Adjustment Clause	5,876,000.00	
Gas Supply Clause/PBR	4,598,211.14	
MISO Exit Fee	634,660.30	
Rate Case Expenses	624,491.12	
KCCS Funding	530,482.81	
EKPC FERC Transmission Costs	339,144.72	
CMRG Funding	138,210.00	
General Management Audit	121,406.53	
Enviromental Cost Recovery	38,337.00	
Other Deferred Debits	1,224,882.41	1,224,882.41
Total Assets	$ 3,594,391,372.92	$ 3,594,391,372.92

* Excludes:

	$	Mcf
Non-recoverable Base Gas	9,648,855.00	7,880,000
Recoverable Base Gas	2,139,990.00	2,930,000
	11,788,845.00	10,810,000

March 21, 2012

Louisville Gas and Electric Company
Summary Trial Balance
February 29, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 1,380,618,780.64
Common Stock	425,170,424.09	
Less: Common Stock Expense	835,888.64	
Paid-In Capital	83,581,499.00	
Retained Earnings	872,702,746.19	
Pollution Control Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,378,185.76	531,378,185.76
Accounts Payable		96,978,222.55
Regular	88,988,635.37	
Employee Withholdings Payable	5,481,128.45	
Salaries and Wages Accrued	2,508,458.73	
Accounts Payable to Associated Companies		13,291,277.31
LG&E and KU Services/Kentucky Utilities	13,291,277.31	
Customers' Deposits	22,518,161.40	22,518,161.40
Taxes Accrued	23,830,129.23	23,830,129.23
Interest Accrued		9,522,801.62
Jefferson County 2000 Series A due 05/01/27 5.375%	17,855.42	
Trimble County 2000 Series A due 08/01/30 Var%	3,055.62	
Jefferson County 2001 Series A due 09/01/26 Var%	8,385.25	
Jefferson County 2001 Series A due 09/01/27 Var%	67.36	
Jefferson County 2001 Series B due 11/01/27 Var%	3,442.62	
Trimble County 2001 Series A due 09/01/26 Var%	2,937.84	
Trimble County 2001 Series A due 10/01/32 Var%	4,007.13	
Trimble County 2001 Series B due 11/01/27 Var%	3,442.62	
Louisville Metro 2003 Series A due 10/01/33 1.900%	1,013,333.33	
Louisville Metro 2005 Series A due 02/01/35 5.750%	185,277.78	
Louisville Metro 2007 Series A due 06/01/33 5.625%	435,937.50	
Louisville Metro 2007 Series B due 06/01/33 1.900%	167,200.00	
Trimble County 2007 Series A due 06/01/33 4.600%	690,000.00	
Interest Rate Swaps	651,670.52	
First Mortgage Bond due 11/15/15 1.625%	1,196,180.56	
First Mortgage Bond due 11/15/40 5.125%	4,300,729.17	
Customers' Deposits	817,249.73	
Interest Accrued on Tax Liabilities	14,000.00	
Other	8,029.17	
Dividends Declared		15,000,000.00
Dividend Payable to LG&E and KU Energy LLC	15,000,000.00	
Miscellaneous Current and Accrued Liabilities		27,524,482.90
No-Notice Gas Payable	8,971,412.32	
Vacation Pay Accrued	5,980,227.35	
Customer Overpayments	5,253,608.11	
Derivative Liability - ASC 815	4,559,185.22	
Tax Collections Payable	1,163,138.42	
Home Energy Assistance	709,282.80	
Retirement Income Liability	436,163.62	
Unearned Revenue	256,757.51	
Other	194,707.55	

March 21, 2012

Louisville Gas and Electric Company
Summary Trial Balance
February 29, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Accumulated Deferred Income Taxes		$ 499,655,847.55
Federal		
Electric	350,820,895.43	
Gas	81,862,099.14	
State		
Electric	54,295,012.50	
Gas	12,677,840.48	
Investment Tax Credit		42,272,132.13
Advanced Coal Credit	23,029,844.00	
Job Development Credit		
Electric	18,707,017.98	
Gas	535,270.15	
Regulatory Liabilities		59,483,304.96
Deferred Taxes		
Federal		
Electric	27,503,680.54	
Gas	1,082,516.16	
State		
Electric	15,083,739.54	
Gas	2,461,807.12	
Gas Supply Clause/PBR	5,607,599.51	
DSM Cost Recovery	3,877,740.96	
Asset Retirement Obligations		
Gas	2,153,553.55	
Electric	199,103.33	
MISO Schedule 10 Charges	657,063.60	
Purchased Gas Adjustment - Tennessee Gas	458,485.65	
Environmental Cost Recovery	398,015.00	
Customers' Advances for Construction		7,342,362.81
Line Extensions		
Gas	6,368,815.99	
Electric	960,946.82	
Other	12,600.00	
Asset Retirement Obligations		59,088,992.03
Electric	37,116,498.76	
Gas	21,863,407.10	
Common	109,086.17	
Other Deferred Credits	10,978,950.12	10,978,950.12
Miscellaneous Long-Term Liabilities		58,881,944.50
Long-Term Derivative Liabilities - ASC 815	53,190,651.46	
Workers' Compensation	5,691,293.04	
Accumulated Provision for Benefits		161,721,797.41
Postretirement Benefits - ASC 715	85,739,223.91	
Pension Payable	72,497,083.50	
Post Employment Benefits Payable	3,689,805.00	
Post Employment Medicare Subsidy	(204,315.00)	
Total Liabilities and Stockholders' Equity	$ 3,594,391,372.92	$ 3,594,391,372.92

March 21, 2012

Louisville Gas and Electric Company
Statement of Cash Flows
February 29, 2012

	Year to Date	
	2012	2011
Cash Flows from Operating Activities		
Net income	$ 18,773,188.80	$ 31,803,558.80
Items not requiring (providing) cash currently:		
Depreciation	23,887,598.80	22,875,634.84
Amortization	1,440,220.06	1,281,835.11
Deferred income taxes - net	76,149.99	6.82
Investment tax credit - net	(446,712.00)	(445,401.00)
Gain on disposal of assets	(1,532.28)	-
Other	3,767,064.23	(1,865,604.87)
Change in receivables	4,222,666.40	32,086,281.75
Change in inventory	21,164,347.79	31,459,264.46
Change in allowance inventory	(16,164.12)	246.07
Change in payables and accrued expenses	30,122,790.67	(21,259,217.39)
Change in regulatory assets	1,036,770.52	(9,905,843.70)
Change in regulatory liabilities	865,708.56	13,755,946.80
Change in other deferred debits	(1,408,037.52)	1,381,459.03
Change in other deferred credits	5,979,053.42	3,083,019.94
Pension and postretirement funding	(22,560,500.00)	(65,337,400.00)
Other	(2,294,910.07)	4,197,263.15
Net cash provided (used) by operating activities	84,607,703.25	43,111,049.81
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(35,544,256.86)	(21,981,213.87)
Gross additions to common utility plant - construction expenditures	(1,125,705.91)	743,866.71
Proceeds received from sales of property	1,532.28	-
Change in restricted cash	(1,451,541.25)	-
Change in non-hedging derivatives	-	(65,560.75)
Other	(1,510,347.88)	(1,092,884.77)
Net cash provided (used) by investing activities	(39,630,319.62)	(22,395,792.68)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(25,578.45)	162,583,905.46
Net change in short-term debt	-	(169,212,000.00)
Dividends on common stock	(15,000,000.00)	-
Net cash provided (used) by financing activities	(15,025,578.45)	(6,628,094.54)
Net Increase (Decrease) in Cash and Cash Equivalents	29,951,805.18	14,087,162.59
Cash and Cash Equivalents at Beginning of Period	24,953,548.52	2,126,011.84
Cash and Cash Equivalents at End of Period	$ 54,905,353.70	$ 16,213,174.43

March 21, 2012

Louisville Gas and Electric 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						
Jefferson County 2000 Series A due 05/01/27 5.375%.......................	$ 17,855.42	$ 111,979.18	$ 36,139.59	$ 223,958.36	$ 1,061,847.93	$ 1,343,749.94
Trimble County 2000 Series A due 08/01/30 Var%............................	3,703.78	26,088.47	7,963.13	57,628.44	141,206.53	422,242.20
Jefferson County 2001 Series A due 09/01/26 Var%.........................	1,740.15	2,598.97	2,958.25	5,894.00	16,127.00	49,692.00
Jefferson County 2001 Series A due 09/01/27 Var%..........................	5,526.63	21,575.34	11,336.06	45,462.33	132,614.16	211,808.24
Jefferson County 2001 Series B due 11/01/27 Var%.........................	11,092.90	22,630.14	23,476.77	48,864.38	246,924.19	362,938.01
Trimble County 2001 Series A due 09/01/26 Var%............................	4,831.29	9,493.15	9,903.01	20,154.12	88,281.77	155,130.16
Trimble County 2001 Series A due 10/01/32 Var%............................	4,485.25	14,757.40	6,740.19	30,131.21	88,743.74	310,939.99
Trimble County 2001 Series B due 11/01/27 Var%............................	11,092.90	22,821.92	23,476.77	49,335.62	245,031.28	363,453.34
Louisville Metro 2003 Series A due 10/01/33 1.900%.......................	202,666.66	202,666.67	405,333.32	329,263.93	2,427,002.62	329,263.93
Louisville Metro 2005 Series A due 02/01/35 5.750%.......................	191,666.66	191,666.67	383,333.32	383,333.34	2,299,999.96	2,299,999.91
Louisville Metro 2007 Series A due 06/01/33 5.625%.......................	145,312.51	145,312.49	290,625.02	290,624.98	1,743,749.92	1,743,749.93
Louisville Metro 2007 Series B due 06/01/33 1.900%........................	55,733.34	55,733.34	109,608.90	90,547.60	667,425.80	90,547.60
Trimble County 2007 Series A due 06/01/33 4.600%.........................	230,000.00	230,000.00	460,000.00	460,000.00	2,760,000.00	2,760,000.00
Interest Rate Swaps..	651,670.52	644,419.48	1,261,273.62	1,221,869.02	7,812,126.51	7,714,721.36
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/15/15 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 11/15/40 5.125%..	1,217,187.51	1,217,187.50	2,434,375.02	2,434,375.00	14,606,250.02	4,260,156.25
Fidelia/PPL..	-	-	-	-	-	18,880,275.03
Revolving Credit Agreement...	-	-	-	185,005.01	-	779,683.35
Total...	3,093,107.19	3,257,472.39	6,143,626.31	6,553,530.68	38,399,831.42	43,263,247.09
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense..	159,869.76	173,347.18	319,739.52	346,013.59	2,071,852.38	768,351.92
Amortization of Loss on Reacquired Debt..	102,453.13	101,002.97	204,898.68	202,005.94	1,216,239.52	1,211,620.84
Total...	262,322.89	274,350.15	524,638.20	548,019.53	3,288,091.90	1,979,972.76
Other Interest Charges						
Customers' Deposits...	112,876.38	100,128.43	222,489.58	209,241.35	1,396,883.22	1,362,619.27
Other Tax Deficiencies..	-	-	-	-	14,000.00	(17,500.00)
Interest on DSM Cost Recovery..	135.88	1,234.22	(9,746.30)	2,311.25	3,039.97	26,828.69
Interest on Debt to Associated Companies..	-	4,185.53	94.83	8,802.56	955.36	225,557.86
Other Interest Expense...	82,158.64	41,552.12	168,174.81	84,090.54	1,200,173.27	962,302.93
Total...	195,170.90	147,100.30	381,012.92	304,445.70	2,615,051.82	2,559,808.75
Total Interest..	$ 3,550,600.98	$ 3,678,922.84	$ 7,049,277.43	$ 7,405,995.91	$ 44,302,975.14	$ 47,803,028.60

March 21, 2012

Louisville Gas and Electric 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	$ 1,545,658.00	$ 1,449,790.00	$ 3,091,316.00	$ 2,899,580.00
Unemployment	42,315.33	34,580.50	149,742.16	90,878.34
FICA	553,014.50	618,060.70	1,355,898.78	1,248,157.14
Public Service Commission Fee	162,886.60	161,096.90	325,773.20	322,193.80
Federal Income	2,800,341.89	6,404,946.04	10,106,125.84	16,346,959.31
State Income	510,700.66	1,168,075.26	1,843,791.96	2,981,208.38
Miscellaneous	3,281.57	-	6,528.14	7,222.67
Total Charged to Operating Expense	5,618,198.55	9,836,549.40	16,879,176.08	23,896,199.64
Taxes Charged to Other Accounts	(119,703.91)	721,376.38	(4,164,907.23)	975,317.32
Taxes Accrued on Intercompany Accounts	(39,048.19)	(254,806.97)	(74,939.44)	(533,038.09)
Total Taxes Charged	$ 5,459,446.45	$ 10,303,118.81	$ 12,639,329.41	$ 24,338,478.87

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	$ 11,998,424.82	$ 3,120,434.00	$ 416.07	$ 15,118,442.75
Unemployment	53,328.91	137,002.48	23,296.72	167,034.67
FICA	526,035.87	1,092,215.15	940,592.91	677,658.11
Federal Income	-	7,077,730.96	-	7,077,730.96
State Income	-	409,311.92	-	409,311.92
Kentucky Sales and Use Tax	671,793.23	819,670.38	1,120,948.69	370,514.92
Miscellaneous	35,266.73	(17,035.48)	8,795.35	9,435.90
Totals	$ 13,284,849.56	$ 12,639,329.41	$ 2,094,049.74	$ 23,830,129.23

March 21, 2012

Louisville Gas and Electric Company
Summary of Utility Plant
February 29, 2012

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant In Service**						
Common						
Common General Plant..	$ 157,057,082.39	$ 2,309,004.08	$ (122,833.70)	$ -	$ 2,186,170.38	$ 159,243,252.77
Common Intangible Plant......................................	60,891,162.83	400,877.35	-	-	400,877.35	61,292,040.18
	217,948,245.22	2,709,881.43	(122,833.70)	-	2,587,047.73	220,535,292.95
Electric						
Electric Distribution...	964,513,175.85	11,731,131.55	(936,357.47)	(23.74)	10,794,750.34	975,307,926.19
Electric General Plant..	15,943,111.49	179,252.16	(39,209.64)	-	140,042.52	16,083,154.01
Electric Hydro Production.....................................	42,535,934.10	16,456.36	(507.91)	-	15,948.45	42,551,882.55
Electric Intangible Plant...	2,240.29	-	-	-	-	2,240.29
Electric Other Production......................................	234,246,978.99	3,514,154.86	(676,874.51)	-	2,837,280.35	237,084,259.34
Electric Steam Production......................................	2,114,510,864.74	3,493,297.31	(519,111.54)	-	2,974,185.77	2,117,485,050.51
Electric Transmission...	254,611,190.87	5,359,150.46	(1,421,397.62)	-	3,937,752.84	258,548,943.71
	3,626,363,496.33	24,293,442.70	(3,593,458.69)	(23.74)	20,699,960.27	3,647,063,456.60
Gas						
Gas Distribution...	592,951,320.42	2,391,365.11	(17,640.22)	-	2,373,724.89	595,325,045.31
Gas General Plant..	8,204,172.47	478,556.74	-	-	478,556.74	8,682,729.21
Gas Intangible Plant...	387.49	-	-	-	-	387.49
Gas Storage..	80,580,078.39	419,144.50	(46,029.52)	-	373,114.98	80,953,193.37
Gas Transmission...	21,541,957.36	882,947.47	(1,389.93)	-	881,557.54	22,423,514.90
	703,277,916.13	4,172,013.82	(65,059.67)	-	4,106,954.15	707,384,870.28
Total 101 Accounts……………………………	4,547,589,657.68	31,175,337.95	(3,781,352.06)	(23.74)	27,393,962.15	4,574,983,619.83
105 **Plant Held For Future Use**						
Electric						
Electric Distribution...	649,014.48	-	-	-	-	649,014.48
Electric Steam Production......................................	-	-	-	-	-	-
	649,014.48	-	-	-	-	649,014.48
Total 105001……………………………………	$ 649,014.48	$ -	$ -	$ -	$ -	$ 649,014.48

March 21, 2012

Louisville Gas and Electric Company
Summary of Utility Plant
February 29, 2012

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
106 **Completed Construction Not Classified**						
Common						
Common General Plant..	$ 2,574,936.01	$ (805,668.73)	$ -	$ -	$ (805,668.73)	$ 1,769,267.28
Common Intangible Plant......................................	2,240,884.26	3,000,769.22	-	-	3,000,769.22	5,241,653.48
	4,815,820.27	2,195,100.49	-	-	2,195,100.49	7,010,920.76
Electric						
Electric Distribution...	23,212,235.54	16,386,508.47	-	-	16,386,508.47	39,598,744.01
Electric General Plant..	6,763.22	63,825.04	-	-	63,825.04	70,588.26
Electric Hydro Production.....................................	16,456.36	(16,456.36)	-	-	(16,456.36)	-
Electric Intangible Plant...	-	-	-	-	-	-
Electric Other Production......................................	3,535,959.74	(3,360,014.83)	-	-	(3,360,014.83)	175,944.91
Electric Steam Production......................................	41,241,674.58	(596,969.09)	-	-	(596,969.09)	40,644,705.49
Electric Transmission...	37,708,783.02	1,560,138.77	-	-	1,560,138.77	39,268,921.79
	105,721,872.46	14,037,032.00	-	-	14,037,032.00	119,758,904.46
Gas						
Gas Distribution...	18,865,984.48	11,240,073.90	-	-	11,240,073.90	30,106,058.38
Gas General Plant..	263,073.78	(99,720.40)	-	-	(99,720.40)	163,353.38
Gas Intangible Plant...	-	-	-	-	-	-
Gas Storage..	514,613.00	5,403,302.10	-	-	5,403,302.10	5,917,915.10
Gas Transmission...	1,459,528.03	(919,105.01)	-	-	(919,105.01)	540,423.02
	21,103,199.29	15,624,550.59	-	-	15,624,550.59	36,727,749.88
Total 106 Accounts	131,640,892.02	31,856,683.08	-	-	31,856,683.08	163,497,575.10
117 **Gas Stored Underground-Noncurrent**						
Gas						
Gas Stored Nonrecoverable...................................	2,139,990.00	-	-	-	-	2,139,990.00
	2,139,990.00	-	-	-	-	2,139,990.00
Total 117001	2,139,990.00	-	-	-	-	2,139,990.00
121 **Nonutility Property**						
Common						
Non Utility Property..	75,239.56	-	-	-	-	75,239.56
	75,239.56	-	-	-	-	75,239.56
Total 121001	75,239.56	-	-	-	-	75,239.56
107 **Construction Work In Progress**						
Common..	15,083,939.33	(3,779,276.01)	-	-	(3,779,276.01)	11,304,663.32
Electric..	152,710,828.07	(20,457,318.46)	-	-	(20,457,318.46)	132,253,509.61
Gas..	47,481,609.94	(12,586,524.60)	-	-	(12,586,524.60)	34,895,085.34
	215,276,377.34	(36,823,119.07)	-	-	(36,823,119.07)	178,453,258.27
Total Plant (Non-CWIP).......................................	4,682,094,793.74	63,032,021.03	(3,781,352.06)	(23.74)	59,250,645.23	4,741,345,438.97
Total Plant + CWIP...	4,897,371,171.08	26,208,901.96	(3,781,352.06)	(23.74)	22,427,526.16	4,919,798,697.24
Total Plant + CWIP - Non Utility..............................	$ 4,897,295,931.52	$ 26,208,901.96	$ (3,781,352.06)	$ (23.74)	$ 22,427,526.16	$ 4,919,723,457.68

March 21, 2012

Louisville Gas and Electric 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										
Common General Plant..	$ (77,087,119.39)	$ (2,011,925.10)	$ 122,833.70	$ -	$ -	$ -	$ -	$ -	$ -	$ (78,976,210.79)
Common General Plant - ARO..	(2,403.59)	(343.40)	-	-	-	-	-	-	-	(2,746.99)
Electric Distribution...	(287,667,187.72)	(3,020,054.03)	936,357.47	-	-	-	-	-	-	(289,750,884.28)
Electric Distribution - ARO...	(7,290.40)	(1,899.85)	-	(223.56)	-	-	-	-	-	(9,413.81)
Electric General Plant..	(11,305,192.13)	(91,118.95)	39,209.64	-	-	-	-	-	-	(11,357,101.44)
Electric Hydro Production..	(10,051,997.22)	(94,312.73)	507.91	-	-	-	-	-	-	(10,145,802.04)
Electric Hydro Production - ARO..	(2,112.62)	(291.42)	-	-	-	-	-	-	-	(2,404.04)
Electric Other Production...	(67,466,740.67)	(1,397,360.69)	676,874.51	-	-	-	-	-	-	(68,187,226.85)
Electric Other Production - ARO...	(1,302.82)	(193.12)	-	-	-	-	-	-	-	(1,495.94)
Electric Steam Production..	(1,060,614,162.86)	(9,571,771.91)	519,111.54	-	-	-	-	-	-	(1,069,666,823.23)
Electric Steam Production - ARO..	(1,402,047.92)	(298,824.15)	-	-	-	-	-	-	-	(1,700,872.07)
Electric Transmission..	(121,989,304.84)	(751,169.49)	1,421,397.62	-	-	-	-	-	-	(121,319,076.71)
Electric Transmission - ARO...	(903.28)	(1,359.22)	-	-	-	-	-	-	-	(2,262.50)
Gas Distribution..	(131,835,425.42)	(2,021,442.56)	17,640.22	-	-	-	-	-	-	(133,839,227.76)
Gas Distribution - ARO..	(346,237.51)	(49,457.31)	-	-	-	-	-	-	-	(395,694.82)
Gas General Plant..	(5,044,235.87)	(60,631.46)	-	-	-	-	-	-	-	(5,104,867.33)
Gas Storage..	(31,071,784.79)	(200,657.62)	46,029.52	-	-	-	-	-	-	(31,226,412.89)
Gas Storage - ARO...	(257,551.24)	(36,696.92)	-	-	-	-	-	-	-	(294,248.16)
Gas Stored Nonrecoverable..	-	-	-	-	-	-	-	-	-	-
Gas Transmission...	(9,486,356.38)	(10,142.48)	1,389.93	-	-	-	-	-	-	(9,495,108.93)
Gas Transmission - ARO..	(35,270.86)	(17,635.43)	-	-	-	-	-	-	-	(52,906.29)
Non Utility Property..	(63,360.36)	-	-	-	-	-	-	-	-	(63,360.36)
	(1,815,737,987.89)	(19,637,287.84)	3,781,352.06	(223.56)	-	-	-	-	-	(1,831,594,147.23)
Cost Of Removal										
Common General Plant..	(637,762.44)	(48,120.63)	-	-	-	-	5,901.84	-	-	(679,981.23)
Electric Distribution...	(148,949,763.17)	(1,199,582.20)	-	-	-	-	989,356.42	-	-	(149,159,988.95)
Electric General Plant..	3,866.64	-	-	-	-	-	-	-	-	3,866.64
Electric Hydro Production..	732,455.11	(7,158.72)	-	-	-	-	1,017.40	-	-	726,313.79
Electric Other Production...	(2,535,958.71)	(59,901.92)	-	-	-	-	170,979.16	-	-	(2,424,881.47)
Electric Steam Production..	(108,291,391.50)	(2,867,816.05)	-	-	-	-	499,831.85	-	-	(110,659,375.70)
Electric Transmission..	(25,759,724.87)	(241,549.60)	-	-	-	-	396,304.48	-	-	(25,604,969.99)
Gas Distribution..	(62,001,399.83)	(569,921.42)	-	-	-	-	59,719.42	-	-	(62,511,601.83)
Gas General Plant..	(0.02)	-	-	-	-	-	-	-	-	(0.02)
Gas Storage..	262,470.54	(25,859.35)	-	-	-	-	-	-	-	236,611.19
Gas Stored Nonrecoverable..	-	-	-	-	-	-	-	-	-	-
Gas Transmission...	(2,984,857.77)	(2,510.79)	-	-	-	-	21,090.05	-	-	(2,966,278.51)
Non Utility Property..	-	-	-	-	-	-	-	-	-	-
	$ (350,162,066.02)	$ (5,022,420.68)	$ -	$ -	$ -	$ -	$ 2,144,200.62	$ -	$ -	$ (353,040,286.08)

March 21, 2012

Louisville Gas and Electric 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
Salvage										
Common General Plant	$ 278,457.83	$ 63.88	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 278,521.71
Electric Distribution	18,531,222.48	244,631.52	-	-	-	-	-	(54,967.23)	-	18,720,886.77
Electric General Plant	140,589.22	386.22	-	-	-	-	-	-	-	140,975.44
Electric Hydro Production	376,638.17	-	-	-	-	-	-	-	-	376,638.17
Electric Other Production	(18,998.67)	-	-	-	-	-	-	-	-	(18,998.67)
Electric Steam Production	24,020,678.65	341,384.65	-	-	-	-	-	(11,875.00)	-	24,350,188.30
Electric Transmission	6,511,015.77	44,606.11	-	-	-	-	-	(199,612.39)	-	6,356,009.49
Gas Distribution	3,791,455.11	34,049.64	-	-	-	-	-	-	-	3,825,504.75
Gas General Plant	228,159.61	482.69	-	-	-	-	-	-	-	228,642.30
Gas Storage	287,152.21	2,974.10	-	-	-	-	-	-	-	290,126.31
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	223,309.53	941.55	-	-	-	-	-	-	-	224,251.08
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	54,369,679.91	669,520.36	-	-	-	-	-	(266,454.62)	-	54,772,745.65
Total Reserves										
Common	(77,512,187.95)	(2,060,325.25)	122,833.70	-	-	-	5,901.84	-	-	(79,443,777.66)
Electric	(1,795,747,613.36)	(18,973,355.55)	3,593,458.69	(223.56)	-	-	2,057,489.31	(266,454.62)	-	(1,809,336,699.09)
Gas	(238,270,572.69)	(2,956,507.36)	65,059.67	-	-	-	80,809.47	-	-	(241,081,210.91)
	(2,111,530,374.00)	(23,990,188.16)	3,781,352.06	(223.56)	-	-	2,144,200.62	(266,454.62)	-	(2,129,861,687.66)
Retirement Work In Progress										
Common	149,762.35	-	-	-	-	(5,901.84)	(29,284.35)	(10,496.95)	-	104,079.21
Electric	11,924,715.03	-	-	-	-	(1,791,034.69)	1,567,788.71	(111,275.97)	(77,311.22)	11,512,881.86
Gas	1,590,687.78	-	-	-	-	(80,809.47)	195,006.99	(398.26)	-	1,704,487.04
	13,665,165.16	-	-	-	-	(1,877,746.00)	1,733,511.35	(122,171.18)	(77,311.22)	13,321,448.11
YTD ACTIVITY	(2,097,865,208.84)	(23,990,188.16)	3,781,352.06	(223.56)	-	(1,877,746.00)	3,877,711.97	(388,625.80)	(77,311.22)	(2,116,540,239.55)
Amortization										
Common	(20,071,604.03)	(1,440,220.06)	-	-	-	-	-	-	-	(21,511,824.09)
Electric	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-
AMORTIZATION TOTAL	(20,071,604.03)	(1,440,220.06)	-	-	-	-	-	-	-	(21,511,824.09)
Depreciation & Amortization Total	$ (2,117,936,812.87)	$ (25,430,408.22)	$ 3,781,352.06	$ (223.56)	$ -	$ (1,877,746.00)	$ 3,877,711.97	$ (388,625.80)	$ (77,311.22)	$ (2,138,052,063.64)
Depr & Amort - Nonutility for Balance Sheet										(2,137,988,703.28)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)	$ 2,779,422,479.01									$ 2,781,734,754.40

March 21, 2012

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
February 29, 2012

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues.......................................	$ 76,140,406.22	$ -	$ 76,140,406.22
Gas Operating Revenues...	37,643,413.75	-	37,643,413.75
Total Operating Revenues..	113,783,819.97	-	113,783,819.97
Fuel for Electric Generation..	28,081,303.76	-	28,081,303.76
Power Purchased...	3,787,880.17	-	3,787,880.17
Gas Supply Expenses..	20,484,139.27	-	20,484,139.27
Other Operation Expenses...	18,991,439.19	-	18,991,439.19
Maintenance..	15,573,622.75	-	15,573,622.75
Depreciation..	11,967,373.42	-	11,967,373.42
Amortization Expense...	734,402.48	-	734,402.48
Regulatory Credits...	(438,995.64)	-	(438,995.64)
Taxes			
Federal Income...	2,800,341.89	-	2,800,341.89
State Income..	510,700.66	-	510,700.66
Deferred Federal Income - Net.................................	-	8,230.80	8,230.80
Deferred State Income - Net.....................................	-	1,501.06	1,501.06
Property and Other...	2,307,156.00	-	2,307,156.00
Amortization of Investment Tax Credit....................	(223,356.00)	-	(223,356.00)
Loss (Gain) from Disposition of Allowances...............	-	-	-
Accretion Expense..	241,844.43	-	241,844.43
Total Operating Expenses..	104,817,852.38	9,731.86	104,827,584.24
Net Operating Income...	8,965,967.59	(9,731.86)	8,956,235.73
Other Income Less Deductions.................................	(204,264.82)	-	(204,264.82)
Income Before Interest Charges................................	8,761,702.77	(9,731.86)	8,751,970.91
Interest on Long-Term Debt..	3,093,107.19	(25,017.63)	3,068,089.56
Amortization of Debt Expense - Net...........................	262,322.89	-	262,322.89
Other Interest Expenses...	195,170.90	-	195,170.90
Total Interest Charges..	3,550,600.98	(25,017.63)	3,525,583.35
Net Income..	$ 5,211,101.79	$ 15,285.77	$ 5,226,387.56

March 21, 2012

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
February 29, 2012

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues..	$ 164,261,143.91	$ -	$ 164,261,143.91
Gas Operating Revenues..	85,143,389.55	-	85,143,389.55
Total Operating Revenues...	249,404,533.46	-	249,404,533.46
Fuel for Electric Generation...	61,912,191.48	-	61,912,191.48
Power Purchased..	9,076,852.03	-	9,076,852.03
Gas Supply Expenses...	48,476,326.51	-	48,476,326.51
Other Operation Expenses...	38,781,848.07	-	38,781,848.07
Maintenance..	23,536,123.14	-	23,536,123.14
Depreciation..	23,887,598.80	-	23,887,598.80
Amortization Expense..	1,440,220.06	-	1,440,220.06
Regulatory Credits...	(889,366.34)	-	(889,366.34)
Taxes			
Federal Income..	10,106,125.84	-	10,106,125.84
State Income...	1,843,791.96	-	1,843,791.96
Deferred Federal Income - Net..................................	76,149.99	16,461.60	92,611.59
Deferred State Income - Net.....................................	-	3,002.12	3,002.12
Property and Other..	4,929,258.28	-	4,929,258.28
Amortization of Investment Tax Credit.....................	(446,712.00)	-	(446,712.00)
Loss (Gain) from Disposition of Allowances................	-	-	-
Accretion Expense...	482,665.52	-	482,665.52
Total Operating Expenses...	223,213,073.34	19,463.72	223,232,537.06
Net Operating Income..	26,191,460.12	(19,463.72)	26,171,996.40
Other Income Less Deductions.................................	(368,993.89)	-	(368,993.89)
Income Before Interest Charges................................	25,822,466.23	(19,463.72)	25,803,002.51
Interest on Long-Term Debt...	6,143,626.31	(50,035.26)	6,093,591.05
Amortization of Debt Expense - Net............................	524,638.20	-	524,638.20
Other Interest Expenses...	381,012.92	-	381,012.92
Total Interest Charges...	7,049,277.43	(50,035.26)	6,999,242.17
Net Income...	$ 18,773,188.80	$ 30,571.54	$ 18,803,760.34

March 21, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
February 29, 2012

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……………………………	$ 882,491,644.40	$ 846,905,423.78	$ (808,717,604.96)	$ (808,371,112.67)	$ 73,774,039.44	$ 38,534,311.11
Add:						
Net Income (Loss) for Period…………………………	5,211,101.79	12,891,386.98	15,285.77	207,559.75	5,226,387.56	13,098,946.73
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	15,000,000.00	17,250,000.00	-	-	15,000,000.00	17,250,000.00
Balance at End of Period…………………………………	$ 872,702,746.19	$ 842,546,810.76	$ (808,702,319.19)	$ (808,163,552.92)	$ 64,000,427.00	$ 34,383,257.84

March 21, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
February 29, 2012

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……………………………	$ 868,929,557.39	$ 827,993,251.96	$ (808,732,890.73)	$ (808,899,282.44)	$ 60,196,666.66	$ 19,093,969.52
Add:						
Net Income (Loss) for Period…………………………	18,773,188.80	31,803,558.80	30,571.54	735,729.52	18,803,760.34	32,539,288.32
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	15,000,000.00	17,250,000.00	-	-	15,000,000.00	17,250,000.00
Balance at End of Period…………………………………	$ 872,702,746.19	$ 842,546,810.76	$ (808,702,319.19)	$ (808,163,552.92)	$ 64,000,427.00	$ 34,383,257.84

March 21, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
February 29, 2012

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……	$ 842,546,810.76	$ 789,099,827.24	$ (808,163,552.92)	$ -	$ 34,383,257.84	$ 789,099,827.24
Add:						
Net Income (Loss) for Period……	111,155,935.43	125,696,983.52	(538,766.27)	783,338.60	110,617,169.16	126,480,322.12
Deduct:						
Adjustment to Retained Earnings……	-	-	-	808,946,891.52	-	808,946,891.52
Common Dividends						
Common Stock Without Par Value……	81,000,000.00	72,250,000.00	-	-	81,000,000.00	72,250,000.00
Balance at End of Period……	$ 872,702,746.19	$ 842,546,810.76	$ (808,702,319.19)	$ (808,163,552.92)	$ 64,000,427.00	$ 34,383,257.84

March 21, 2012

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of February 29, 2012

Assets	Without Purchase Accounting	Purchase Accounting	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 4,919,723,457.68	$ -	$ 4,919,723,457.68
Less: Reserves for Depreciation and Amortization....	2,137,988,703.28	-	2,137,988,703.28
Total..	2,781,734,754.40	-	2,781,734,754.40
Investments			
Ohio Valley Electric Corporation.............................	594,286.00	-	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	-	11,879.20
Special Funds...	30,310,548.45	-	30,310,548.45
Total..	30,916,713.65	-	30,916,713.65
Current and Accrued Assets			
Cash..	38,370,592.06	-	38,370,592.06
Special Deposits..	-	-	-
Temporary Cash Investments...................................	16,534,761.64	-	16,534,761.64
Accounts Receivable - Less Reserve........................	129,860,629.76	-	129,860,629.76
Accounts Receivable from Associated Companies....	15,190,151.03	-	15,190,151.03
Materials and Supplies - At Average Cost			
Fuel..	57,383,128.29	-	57,383,128.29
Plant Materials and Operating Supplies.................	30,831,292.12	-	30,831,292.12
Stores Expense...	5,538,432.48	-	5,538,432.48
Gas Stored Underground.......................................	27,251,651.60	-	27,251,651.60
Emission Allowances...	18,675.79	-	18,675.79
Prepayments..	5,872,637.42	-	5,872,637.42
Miscellaneous Current and Accrued Assets..............	-	-	-
Total..	326,851,952.19	-	326,851,952.19
Deferred Debits and Other			
Unamortized Debt Expense......................................	13,053,099.47	(3,450,087.03)	9,603,012.44
Unamortized Loss on Bonds....................................	20,784,542.53	-	20,784,542.53
Accumulated Deferred Income Taxes.......................	23,749,922.01	67,074,595.36	90,824,517.37
Deferred Regulatory Assets.....................................	396,075,506.26	8,410,666.50	404,486,172.76
Other Deferred Debits..	1,224,882.41	156,913,626.46	158,138,508.87
Goodwill...	-	389,157,351.59	389,157,351.59
Total..	454,887,952.68	618,106,152.88	1,072,994,105.56
Total Assets..	$ 3,594,391,372.92	$ 618,106,152.88	$ 4,212,497,525.80

March 21, 2012

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of February 29, 2012

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting	Total
Proprietary Capital			
Common Stock	$ 425,170,424.09	$ -	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	-	835,888.64
Paid-In Capital	83,581,499.00	1,194,085,869.02	1,277,667,368.02
Other Comprehensive Income	-	-	-
Retained Earnings	872,702,746.19	(808,702,319.19)	64,000,427.00
Total Proprietary Capital	1,380,618,780.64	385,383,549.83	1,766,002,330.47
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	6,176,434.92	580,480,434.92
First Mortgage Bonds	531,378,185.76	-	531,378,185.76
LT Notes Payable to Associated Companies	-	-	-
Total Long-Term Debt	1,105,682,185.76	6,176,434.92	1,111,858,620.68
Total Capitalization	2,486,300,966.40	391,559,984.75	2,877,860,951.15
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies	-	-	-
Accounts Payable	96,978,222.55	-	96,978,222.55
Accounts Payable to Associated Companies	13,291,277.31	-	13,291,277.31
Customer Deposits	22,518,161.40	-	22,518,161.40
Taxes Accrued	23,830,129.23	-	23,830,129.23
Dividends Declared	15,000,000.00	-	15,000,000.00
Interest Accrued	9,522,801.62	-	9,522,801.62
Miscellaneous Current and Accrued Liabilities	27,524,482.90	-	27,524,482.90
Total	208,665,075.01	-	208,665,075.01
Deferred Credits and Other			
Accumulated Deferred Income Taxes	499,655,847.55	64,671,962.20	564,327,809.75
Investment Tax Credit	42,272,132.13	-	42,272,132.13
Regulatory Liabilities	59,483,304.96	156,913,626.46	216,396,931.42
Customer Advances for Construction	7,342,362.81	-	7,342,362.81
Asset Retirement Obligations	59,088,992.03	-	59,088,992.03
Other Deferred Credits	10,978,950.12	4,960,579.47	15,939,529.59
Miscellaneous Long-Term Liabilities	58,881,944.50	-	58,881,944.50
Misc Long-Term Liab Due to Assoc Cos	-	-	-
Accum Provision for Postretirement Benefits	161,721,797.41	-	161,721,797.41
Total	899,425,331.51	226,546,168.13	1,125,971,499.64
Total Liabilities and Stockholders' Equity	$ 3,594,391,372.92	$ 618,106,152.88	$ 4,212,497,525.80

March 21, 2012

LOUISVILLE GAS AND ELECTRIC COMPANY

Financial Reports

January 31, 2012

Index
Financial and Operating Reports

Louisville Gas and Electric Company
January 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.

Louisville Gas and Electric Company
Comparative Statement of Income
January 31, 2012

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues...	$ 88,120,737.69	$ 92,096,734.53	$ (3,975,996.84)	(4.32)
Gas Operating Revenues...	47,499,975.80	58,814,010.67	(11,314,034.87)	(19.24)
Total Operating Revenues..	135,620,713.49	150,910,745.20	(15,290,031.71)	(10.13)
Fuel for Electric Generation..	33,830,887.72	32,317,512.15	1,513,375.57	4.68
Power Purchased...	5,288,971.86	7,074,753.38	(1,785,781.52)	(25.24)
Gas Supply Expenses..	27,992,187.24	38,307,433.47	(10,315,246.23)	(26.93)
Other Operation Expenses...	19,790,408.88	18,426,155.56	1,364,253.32	7.40
Maintenance...	7,962,500.39	6,764,895.92	1,197,604.47	17.70
Depreciation...	11,920,225.38	11,277,201.35	643,024.03	5.70
Amortization Expense...	705,817.58	640,016.30	65,801.28	10.28
Regulatory Credits..	(450,370.70)	(366,611.83)	(83,758.87)	(22.85)
Taxes				
Federal Income...	7,305,783.95	9,942,013.27	(2,636,229.32)	(26.52)
State Income..	1,333,091.30	1,813,133.12	(480,041.82)	(26.48)
Deferred Federal Income - Net...................................	76,149.99	6.82	76,143.17	1,116,468.77
Deferred State Income - Net.......................................	-	-	-	-
Property and Other...	2,622,102.28	2,304,503.85	317,598.43	13.78
Amortization of Investment Tax Credit.....................	(223,356.00)	(209,367.00)	(13,989.00)	(6.68)
Loss (Gain) from Disposition of Allowances................	-	-	-	-
Accretion Expense..	240,821.09	218,662.64	22,158.45	10.13
Total Operating Expenses..	118,395,220.96	128,510,309.00	(10,115,088.04)	(7.87)
Net Operating Income...	17,225,492.53	22,400,436.20	(5,174,943.67)	(23.10)
Other Income Less Deductions..................................	(164,729.07)	238,808.69	(403,537.76)	(168.98)
Income Before Interest Charges................................	17,060,763.46	22,639,244.89	(5,578,481.43)	(24.64)
Interest on Long-Term Debt..	3,050,519.12	3,296,058.29	(245,539.17)	(7.45)
Amortization of Debt Expense - Net.............................	262,315.31	273,669.38	(11,354.07)	(4.15)
Other Interest Expenses...	185,842.02	157,345.40	28,496.62	18.11
Total Interest Charges..	3,498,676.45	3,727,073.07	(228,396.62)	(6.13)
Net Income..	$ 13,562,087.01	$ 18,912,171.82	$ (5,350,084.81)	(28.29)

February 21, 2012

Louisville Gas and Electric Company
Comparative Statement of Income
January 31, 2012

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	Increase or Decrease %
Electric Operating Revenues..	$ 88,120,737.69	$ 92,096,734.53	$ (3,975,996.84)	(4.32)
Gas Operating Revenues...	47,499,975.80	58,814,010.67	(11,314,034.87)	(19.24)
Total Operating Revenues..	135,620,713.49	150,910,745.20	(15,290,031.71)	(10.13)
Fuel for Electric Generation..	33,830,887.72	32,317,512.15	1,513,375.57	4.68
Power Purchased..	5,288,971.86	7,074,753.38	(1,785,781.52)	(25.24)
Gas Supply Expenses...	27,992,187.24	38,307,433.47	(10,315,246.23)	(26.93)
Other Operation Expenses...	19,790,408.88	18,426,155.56	1,364,253.32	7.40
Maintenance...	7,962,500.39	6,764,895.92	1,197,604.47	17.70
Depreciation...	11,920,225.38	11,277,201.35	643,024.03	5.70
Amortization Expense..	705,817.58	640,016.30	65,801.28	10.28
Regulatory Credits...	(450,370.70)	(366,611.83)	(83,758.87)	(22.85)
Taxes				
Federal Income...	7,305,783.95	9,942,013.27	(2,636,229.32)	(26.52)
State Income...	1,333,091.30	1,813,133.12	(480,041.82)	(26.48)
Deferred Federal Income - Net..................................	76,149.99	6.82	76,143.17	1,116,468.77
Deferred State Income - Net......................................	-	-	-	-
Property and Other...	2,622,102.28	2,304,503.85	317,598.43	13.78
Amortization of Investment Tax Credit.....................	(223,356.00)	(209,367.00)	(13,989.00)	(6.68)
Loss (Gain) from Disposition of Allowances...............	-	-	-	-
Accretion Expense...	240,821.09	218,662.64	22,158.45	10.13
Total Operating Expenses...	118,395,220.96	128,510,309.00	(10,115,088.04)	(7.87)
Net Operating Income..	17,225,492.53	22,400,436.20	(5,174,943.67)	(23.10)
Other Income Less Deductions..................................	(164,729.07)	238,808.69	(403,537.76)	(168.98)
Income Before Interest Charges................................	17,060,763.46	22,639,244.89	(5,578,481.43)	(24.64)
Interest on Long-Term Debt...	3,050,519.12	3,296,058.29	(245,539.17)	(7.45)
Amortization of Debt Expense - Net............................	262,315.31	273,669.38	(11,354.07)	(4.15)
Other Interest Expenses..	185,842.02	157,345.40	28,496.62	18.11
Total Interest Charges...	3,498,676.45	3,727,073.07	(228,396.62)	(6.13)
Net Income...	$ 13,562,087.01	$ 18,912,171.82	$ (5,350,084.81)	(28.29)

February 21, 2012

Louisville Gas and Electric 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	$ 1,055,774,306.65	$ 1,032,051,999.60	$ 23,722,307.05	2.30
Gas Operating Revenues	293,260,386.95	312,177,991.63	(18,917,604.68)	(6.06)
Total Operating Revenues	1,349,034,693.60	1,344,229,991.23	4,804,702.37	0.36
Fuel for Electric Generation	362,481,768.93	371,789,895.26	(9,308,126.33)	(2.50)
Power Purchased	73,108,765.60	55,167,479.44	17,941,286.16	32.52
Gas Supply Expenses	150,920,379.47	173,365,821.30	(22,445,441.83)	(12.95)
Other Operation Expenses	237,641,608.21	226,993,825.00	10,647,783.21	4.69
Maintenance	117,556,673.02	112,515,683.87	5,040,989.15	4.48
Depreciation	142,641,238.95	131,720,871.83	10,920,367.12	8.29
Amortization Expense	8,199,265.31	7,646,851.79	552,413.52	7.22
Regulatory Credits	(5,813,844.56)	(4,457,140.11)	(1,356,704.45)	(30.44)
Taxes				
Federal Income	9,326,621.13	34,128,940.20	(24,802,319.07)	(72.67)
State Income	7,785,490.85	7,005,404.44	780,086.41	11.14
Deferred Federal Income - Net	52,299,867.53	27,667,011.82	24,632,855.71	89.03
Deferred State Income - Net	2,011,675.35	2,370,024.44	(358,349.09)	(15.12)
Property and Other	28,439,182.07	22,769,139.40	5,670,042.67	24.90
Amortization of Investment Tax Credit	(2,819,721.00)	(2,491,983.00)	(327,738.00)	(13.15)
Loss (Gain) from Disposition of Allowances	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense	2,666,643.07	3,338,204.86	(671,561.79)	(20.12)
Total Operating Expenses	1,186,443,035.99	1,169,495,570.40	16,947,465.59	1.45
Net Operating Income	162,591,657.61	174,734,420.83	(12,142,763.22)	(6.95)
Other Income Less Deductions	675,860.01	10,871,169.70	(10,195,309.69)	(93.78)
Income Before Interest Charges	163,267,517.62	185,605,590.53	(22,338,072.91)	(12.04)
Interest on Long-Term Debt	38,564,196.62	43,640,294.92	(5,076,098.30)	(11.63)
Amortization of Debt Expense - Net	3,300,119.16	1,822,005.63	1,478,113.53	81.13
Other Interest Expenses	2,566,981.22	2,526,924.63	40,056.59	1.59
Total Interest Charges	44,431,297.00	47,989,225.18	(3,557,928.18)	(7.41)
Net Income	$ 118,836,220.62	$ 137,616,365.35	$ (18,780,144.73)	(13.65)

February 21, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings
January 31, 2012

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period...	$ 868,929,557.39	$ 827,993,251.96	$ 868,929,557.39	$ 827,993,251.96	$ 846,905,423.78	$ 764,289,058.43
Add:						
Net Income for Period..	13,562,087.01	18,912,171.82	13,562,087.01	18,912,171.82	118,836,220.62	137,616,365.35
Deduct:						
Common Dividends						
Common Stock Without Par Value.....................	-	-	-	-	83,250,000.00	55,000,000.00
Balance at End of Period...	$ 882,491,644.40	$ 846,905,423.78	$ 882,491,644.40	$ 846,905,423.78	$ 882,491,644.40	$ 846,905,423.78

February 21, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of January 31, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,909,056,549.82	$ 4,750,777,974.71
Less: Reserves for Depreciation and Amortization	2,129,469,771.92	2,049,262,226.20
Total	2,779,586,777.90	2,701,515,748.51
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	29,788,557.01	16,266,282.58
Total	30,394,722.21	16,872,447.78
Current and Accrued Assets		
Cash	22,562,167.83	10,946,085.86
Special Deposits	12,277.00	3,590,045.06
Temporary Cash Investments	33,199.87	1,861.08
Accounts Receivable - Less Reserve	143,404,574.12	172,877,770.06
Accounts Receivable from Associated Companies	12,419,799.02	18,031,905.66
Materials and Supplies - At Average Cost		
Fuel	50,199,426.27	63,040,020.16
Plant Materials and Operating Supplies	30,878,565.61	29,472,535.23
Stores Expense	5,639,880.99	4,987,130.53
Gas Stored Underground	41,005,070.14	43,600,442.97
Emission Allowances	19,936.74	2,624.91
Prepayments	5,317,036.50	6,932,677.50
Miscellaneous Current and Accrued Assets	-	453,145.30
Total	311,491,934.09	353,936,244.32
Deferred Debits and Other		
Unamortized Debt Expense	13,189,647.53	13,553,077.84
Unamortized Loss on Bonds	20,885,609.22	21,833,646.50
Accumulated Deferred Income Taxes	23,749,922.01	53,869,965.22
Deferred Regulatory Assets	399,361,510.17	353,138,961.12
Other Deferred Debits	1,259,355.16	901,719.66
Total	458,446,044.09	443,297,370.34
Total Assets	$ 3,579,919,478.29	$ 3,515,621,810.95

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	882,491,644.40	846,905,423.78
Total Proprietary Capital	1,390,407,678.85	1,354,821,458.23
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,354,864.10	531,075,004.16
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,105,658,864.10	1,105,379,004.16
Total Capitalization	2,496,066,542.95	2,460,200,462.39
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	39,801,000.00
Notes Payable	-	-
Accounts Payable	90,067,704.18	95,342,791.32
Accounts Payable to Associated Companies	15,168,942.65	16,395,004.37
Customer Deposits	22,478,501.90	23,571,825.06
Taxes Accrued	19,172,547.29	11,594,182.53
Interest Accrued	8,169,288.22	7,648,967.20
Miscellaneous Current and Accrued Liabilities	27,349,223.25	26,764,921.93
Total	182,406,207.49	221,118,692.41
Deferred Credits and Other		
Accumulated Deferred Income Taxes	499,655,847.55	473,518,807.92
Investment Tax Credit	42,495,488.13	45,315,209.13
Regulatory Liabilities	60,785,846.15	65,743,017.64
Customer Advances for Construction	7,319,187.89	8,492,300.89
Asset Retirement Obligations	58,847,147.60	52,869,451.55
Other Deferred Credits	8,612,478.80	6,909,404.21
Miscellaneous Long-Term Liabilities	61,995,072.79	33,228,101.47
Accum Provision for Postretirement Benefits	161,735,658.94	148,226,363.34
Total	901,446,727.85	834,302,656.15
Total Liabilities and Stockholders' Equity	$ 3,579,919,478.29	$ 3,515,621,810.95

February 21, 2012

Louisville Gas and Electric Company
Statement of Capitalization and Short-Term Debt
January 31, 2012

	Authorized Shares	Issued and Outstanding Shares	Issued and Outstanding Amount	Percent of Total Capital
Proprietary Capital				
Common Stock - Without Par..........	75,000,000	21,294,223	$ 425,170,424.09	
Less: Common Stock Expense..........			835,888.64	
Paid-In Capital..........			83,581,499.00	
Other Comprehensive Income..........			-	
Retained Earnings..........			882,491,644.40	
Total Proprietary Capital..........			1,390,407,678.85	55.70
Long-Term Debt				
Pollution Control Bonds..........				
Jefferson County 2000 Series A due 05/01/27 5.375%..........			25,000,000.00	
Trimble County 2000 Series A due 08/01/30 Var%..........			83,335,000.00	
Jefferson County 2001 Series A due 09/01/26 Var%..........			22,500,000.00	
Jefferson County 2001 Series A due 09/01/27 Var%..........			10,104,000.00	
Jefferson County 2001 Series B due 11/01/27 Var%..........			35,000,000.00	
Trimble County 2001 Series A due 09/01/26 Var%..........			27,500,000.00	
Trimble County 2001 Series A due 10/01/32 Var%..........			41,665,000.00	
Trimble County 2001 Series B due 11/01/27 Var%..........			35,000,000.00	
Louisville Metro 2003 Series A due 10/01/33 1.900%..........			128,000,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%..........			40,000,000.00	
Louisville Metro 2007 Series A due 06/01/33 5.625%..........			31,000,000.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%..........			35,200,000.00	
Trimble County 2007 Series A due 06/01/33 4.600%..........			60,000,000.00	
Total Pollution Control Bonds..........			574,304,000.00	23.01
First Mortgage Bonds..........				
First Mortgage Bond Due 11/15/15 1.625%..........			250,000,000.00	
First Mortgage Bond Due 11/15/40 5.125%..........			285,000,000.00	
Total First Mortgage Bonds..........			535,000,000.00	21.44
Less: First Mortgage Bonds Debt Discount..........				
First Mortgage Bond Due 11/15/15 1.625%..........			(669,229.20)	
First Mortgage Bond Due 11/15/40 5.125%..........			(2,975,906.70)	
			(3,645,135.90)	(0.15)
Total First Mortgage Bonds - Net of Debt Discount..........			531,354,864.10	21.29
Total Capitalization..........			$ 2,496,066,542.95	100.00

February 21, 2012

Louisville Gas and Electric Company
Summary Trial Balance
January 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 4,909,056,549.82	$ 4,909,056,549.82
Reserves for Depreciation and Amortization		(2,129,469,771.92)
Depreciation of Plant		
Electric	(1,792,238,506.73)	
Gas	(238,088,966.32)	
Common	(78,364,877.26)	
Amortization of Plant		
Common	(20,777,421.61)	
Investments		30,394,722.21
Special Funds	29,788,557.01	
Ohio Valley Electric Corporation	594,286.00	
Nonutility Property	11,879.20	
Cash	22,562,167.83	22,562,167.83
Special Deposits		12,277.00
Restricted Cash - Short Term	12,277.00	
Temporary Cash Investments	33,199.87	33,199.87
Accounts Receivable - Less Reserve		143,404,574.12
Customers - Active	73,702,755.97	
Unbilled Revenues	62,040,552.88	
IMPA	2,929,514.73	
IMEA	2,849,854.45	
Wholesale Sales	1,065,938.48	
Sundry Accounts Receivable	946,125.79	
Transmission Sales	552,384.39	
Damage Claims	460,172.21	
Electricity Swaps	166,354.87	
Income Tax Receivable - State	81,359.15	
Bechtel Liquidated Damages	5,890.00	
Other	526,729.54	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	606,797.56	
Reserve	(1,485,539.00)	
Accrual	(517,757.92)	
A/R Miscellaneous	(271,164.47)	
LEM Reserve	(166,354.87)	
Recoveries	(89,039.64)	
Accounts Receivable from Associated Companies		12,419,799.02
LG&E and KU Services/Kentucky Utilities	12,419,799.02	
Fuel		50,199,426.27
Coal 983,508.87 Tons @ $50.34; MMBtu 22,094,271.56 @ 224.08¢	49,509,474.16	
Fuel Oil 203,750.08 Gallons @ 266.47¢	542,927.11	
Gas Pipeline 5,100 Mcf @ $28.83	147,025.00	
Plant Materials and Operating Supplies		30,878,565.61
Regular Materials and Supplies	29,933,028.03	
Limestone 105,455.53 Tons @ $8.97	945,537.58	
Stores Expense Undistributed	5,639,880.99	5,639,880.99
Gas Stored Underground - Current		41,005,070.14
Gas Stored Underground* 8,826,717 Mcf (14.73 psia) @ $4.65	41,005,070.14	
Emission Allowances	19,936.74	19,936.74

February 21, 2012

Louisville Gas and Electric Company
Summary Trial Balance
January 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Prepayments		$ 5,317,036.50
Insurance	2,261,940.65	
Taxes	814,433.06	
Rights of Way	226,666.71	
Risk Management and Workers Compensation	90,000.00	
Other	1,923,996.08	
Unamortized Debt Expense		13,189,647.53
Trimble County 2000 Series A due 08/01/30 Var%	716,086.43	
Jefferson County 2001 Series A due 09/01/26 Var%	144,721.68	
Jefferson County 2001 Series A due 09/01/27 Var%	317,783.02	
Jefferson County 2001 Series B due 11/01/27 Var%	173,175.19	
Trimble County 2001 Series A due 09/01/26 Var%	157,353.91	
Trimble County 2001 Series B due 11/01/27 Var%	173,203.60	
Trimble County 2002 Series A due 10/01/32 Var%	769,242.55	
Louisville Metro 2003 Series A Due 10/01/33 1.900%	430,874.64	
Louisville Metro 2007 Series B Due 06/01/33 1.900%	165,453.01	
Trimble County 2007 Series A due 06/01/33 4.600%	1,014,067.46	
First Mortgage Bond due 11/15/15 1.625%	1,976,279.82	
First Mortgage Bond due 11/15/40 5.125%	3,432,724.48	
Revolving Credit Agreement	3,718,681.74	
Unamortized Loss on Bonds	20,885,609.22	20,885,609.22
Accumulated Deferred Income Taxes		23,749,922.01
Federal		
Electric	17,577,286.97	
Gas	1,368,281.19	
State		
Electric	4,502,703.92	
Gas	301,649.93	
Regulatory Assets		399,361,510.17
Pension and Postretirement Benefits	225,481,749.00	
Interest Rate Swap Ineffectiveness	61,055,551.84	
2009 Winter Storm	37,262,632.53	
2008 Wind Storm	20,009,282.87	
Deferred Taxes - ASC 740		
Federal		
Electric	12,458,133.70	
State		
Electric	2,272,000.07	
Asset Retirement Obligations		
Electric	9,724,660.02	
Gas	1,382,720.39	
Common	9,773.99	
Swap Termination	8,915,682.12	
2011 Summer Storm	8,052,124.65	
Fuel Adjustment Clause	5,052,000.00	
Gas Supply Clause/PBR	5,003,740.35	
MISO Exit Fee	697,146.50	
Rate Case Expenses	687,522.53	
KCCS Funding	548,775.32	
EKPC FERC Transmission Costs	353,275.76	
CMRG Funding	146,340.00	
Enviromental Cost Recovery	126,992.00	
General Management Audit	121,406.53	
Other Deferred Debits	1,259,355.16	1,259,355.16
Total Assets	$ 3,579,919,478.29	$ 3,579,919,478.29

* Excludes:		$	Mcf
	Non-recoverable Base Gas	9,648,855.00	7,880,000
	Recoverable Base Gas	2,139,990.00	2,930,000
		11,788,845.00	10,810,000

February 21, 2012

Louisville Gas and Electric Company
Summary Trial Balance
January 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 1,390,407,678.85
Common Stock	425,170,424.09	
Less: Common Stock Expense	835,888.64	
Paid-In Capital	83,581,499.00	
Retained Earnings	882,491,644.40	
Pollution Control Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,354,864.10	531,354,864.10
Accounts Payable		90,067,704.18
Regular	82,595,164.59	
Employee Withholdings Payable	5,512,241.96	
Salaries and Wages Accrued	1,960,297.63	
Accounts Payable to Associated Companies		15,168,942.65
LG&E and KU Services/Kentucky Utilities	15,168,942.65	
Customers' Deposits	22,478,501.90	22,478,501.90
Taxes Accrued	19,172,547.29	19,172,547.29
Interest Accrued		8,169,288.22
Jefferson County 2000 Series A due 05/01/27 5.375%	18,285.94	
Trimble County 2000 Series A due 08/01/30 Var%	2,592.64	
Jefferson County 2001 Series A due 09/01/26 Var%	2,858.61	
Jefferson County 2001 Series A due 09/01/27 Var%	61.75	
Jefferson County 2001 Series B due 11/01/27 Var%	7,650.27	
Trimble County 2001 Series A due 09/01/26 Var%	4,575.82	
Trimble County 2001 Series A due 10/01/32 Var%	1,912.49	
Trimble County 2001 Series B due 11/01/27 Var%	7,650.27	
Louisville Metro 2003 Series A due 10/01/33 1.900%	810,666.67	
Louisville Metro 2005 Series A due 02/01/35 5.750%	1,143,611.11	
Louisville Metro 2007 Series A due 06/01/33 5.625%	290,625.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%	111,466.67	
Trimble County 2007 Series A due 06/01/33 4.600%	460,000.00	
Interest Rate Swaps	609,603.10	
First Mortgage Bond due 11/15/15 1.625%	857,638.89	
First Mortgage Bond due 11/15/40 5.125%	3,083,541.67	
Customers' Deposits	734,654.03	
Interest Accrued on Tax Liabilities	14,000.00	
Other	7,893.29	
Miscellaneous Current and Accrued Liabilities		27,349,223.25
No-Notice Gas Payable	7,956,774.40	
Vacation Pay Accrued	5,980,227.35	
Customer Overpayments	5,561,322.28	
Derivative Liability - ASC 815	4,751,772.09	
Tax Collections Payable	1,530,964.90	
Home Energy Assistance	589,344.76	
Retirement Income Liability	436,163.62	
Unearned Revenue	323,531.42	
Other	219,122.43	

Louisville Gas and Electric Company
Summary Trial Balance
January 31, 2012

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Accumulated Deferred Income Taxes		$ 499,655,847.55
Federal		
Electric	350,820,895.43	
Gas	81,862,099.14	
State		
Electric	54,295,012.50	
Gas	12,677,840.48	
Investment Tax Credit		42,495,488.13
Advanced Coal Credit	23,083,189.00	
Job Development Credit		
Electric	18,866,560.98	
Gas	545,738.15	
Regulatory Liabilities		60,785,846.15
Deferred Taxes		
Federal		
Electric	27,503,680.54	
Gas	1,082,516.16	
State		
Electric	15,083,739.54	
Gas	2,461,807.12	
Gas Supply Clause/PBR	7,125,301.18	
DSM Cost Recovery	3,564,858.93	
Asset Retirement Obligations		
Gas	2,151,281.11	
Electric	193,855.98	
MISO Schedule 10 Charges	650,337.16	
Purchased Gas Adjustment - Tennessee Gas	538,501.43	
Environmental Cost Recovery	429,967.00	
Customers' Advances for Construction		7,319,187.89
Line Extensions		
Gas	6,370,387.02	
Electric	936,200.87	
Other	12,600.00	
Asset Retirement Obligations		58,847,147.60
Electric	36,972,491.58	
Gas	21,766,067.55	
Common	108,588.47	
Other Deferred Credits	8,612,478.80	8,612,478.80
Miscellaneous Long-Term Liabilities		61,995,072.79
Long-Term Derivative Liabilities - ASC 815	56,303,779.75	
Workers' Compensation	5,691,293.04	
Accumulated Provision for Benefits		161,735,658.94
Postretirement Benefits - ASC 715	85,753,085.44	
Pension Payable	72,497,083.50	
Post Employment Benefits Payable	3,689,805.00	
Post Employment Medicare Subsidy	(204,315.00)	
Total Liabilities and Stockholders' Equity	$ 3,579,919,478.29	$ 3,579,919,478.29

February 21, 2012

Louisville Gas and Electric Company
Statement of Cash Flows
January 31, 2012

	Year to Date	
	2012	2011
Cash Flows from Operating Activities		
Net income	$ 13,562,087.01	$ 18,912,171.82
Items not requiring (providing) cash currently:		
Depreciation	11,920,225.38	11,277,201.35
Amortization	705,817.58	640,016.30
Deferred income taxes - net	76,149.99	6.82
Investment tax credit - net	(223,356.00)	(209,367.00)
Other	2,003,317.44	391,114.33
Change in receivables	(6,786,962.58)	2,693,539.27
Change in inventory	14,380,746.16	21,169,410.89
Change in allowance inventory	(17,425.07)	104.05
Change in payables and accrued expenses	6,489,566.66	1,226,527.54
Change in regulatory assets	(2,249,233.50)	(9,102,597.95)
Change in regulatory liabilities	2,168,249.75	14,316,669.18
Change in other deferred debits	(454,385.71)	286,809.87
Change in other deferred credits	3,612,582.10	1,366,500.90
Pension and postretirement funding	(22,560,500.00)	(65,337,400.00)
Other	(3,078,059.45)	2,290,829.64
Net cash provided (used) by operating activities	19,548,819.76	(78,462.99)
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(19,903,062.62)	(19,470,192.66)
Gross additions to common utility plant - construction expenditures	(598,955.26)	1,243,389.60
Change in restricted cash	(941,826.81)	-
Change in non-hedging derivatives	-	(7,240.93)
Other	(438,963.89)	(428,108.25)
Net cash provided (used) by investing activities	(21,882,808.58)	(18,662,152.24)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(24,192.00)	162,637,550.33
Net change in short-term debt	-	(135,075,000.00)
Net cash provided (used) by financing activities	(24,192.00)	27,562,550.33
Net Increase (Decrease) in Cash and Cash Equivalents	(2,358,180.82)	8,821,935.10
Cash and Cash Equivalents at Beginning of Period	24,953,548.52	2,126,011.84
Cash and Cash Equivalents at End of Period	$ 22,595,367.70	$ 10,947,946.94

February 21, 2012

Louisville Gas and Electric 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						
Jefferson County 2000 Series A due 05/01/27 5.375%.......................	$ 18,284.17	$ 111,979.18	$ 18,284.17	$ 111,979.18	$ 1,155,971.69	$ 1,343,749.93
Trimble County 2000 Series A due 08/01/30 Var%............................	4,259.35	31,539.97	4,259.35	31,539.97	163,591.22	411,339.22
Jefferson County 2001 Series A due 09/01/26 Var%..........................	1,218.10	3,295.03	1,218.10	3,295.03	16,985.82	48,965.08
Jefferson County 2001 Series A due 09/01/27 Var%..........................	5,809.43	23,886.99	5,809.43	23,886.99	148,662.87	201,106.87
Jefferson County 2001 Series B due 11/01/27 Var%..........................	12,383.87	26,234.24	12,383.87	26,234.24	258,461.43	360,444.85
Trimble County 2001 Series A due 09/01/26 Var%............................	5,071.72	10,660.97	5,071.72	10,660.97	92,943.63	158,927.41
Trimble County 2001 Series A due 10/01/32 Var%............................	2,254.94	15,373.81	2,254.94	15,373.81	99,015.89	303,369.51
Trimble County 2001 Series B due 11/01/27 Var%............................	12,383.87	26,513.70	12,383.87	26,513.70	256,760.30	360,768.40
Louisville Metro 2003 Series A due 10/01/33 1.900%.......................	202,666.66	126,597.26	202,666.66	126,597.26	2,427,002.63	126,597.26
Louisville Metro 2005 Series A due 02/01/35 5.750%.......................	191,666.66	191,666.67	191,666.66	191,666.67	2,299,999.97	2,299,999.91
Louisville Metro 2007 Series A due 06/01/33 5.625%.......................	145,312.51	145,312.49	145,312.51	145,312.49	1,743,749.90	1,743,749.94
Louisville Metro 2007 Series B due 06/01/33 1.900%........................	53,875.56	34,814.26	53,875.56	34,814.26	667,425.80	34,814.26
Trimble County 2007 Series A due 06/01/33 4.600%.........................	230,000.00	230,000.00	230,000.00	230,000.00	2,760,000.00	2,760,000.00
Interest Rate Swaps..	609,603.10	577,449.54	609,603.10	577,449.54	7,804,875.47	7,717,030.98
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/15/15 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 11/15/40 5.125%..	1,217,187.51	1,217,187.50	1,217,187.51	1,217,187.50	14,606,250.01	3,042,968.75
Fidelia/PPL..	-	-	-	-	-	21,100,425.02
Revolving Credit Agreement...	-	185,005.01	-	185,005.01	-	779,683.35
Total..	3,050,519.12	3,296,058.29	3,050,519.12	3,296,058.29	38,564,196.62	43,640,294.92
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense...	159,869.76	172,666.41	159,869.76	172,666.41	2,085,329.80	610,523.08
Amortization of Loss on Reacquired Debt..	102,445.55	101,002.97	102,445.55	101,002.97	1,214,789.36	1,211,482.55
Total..	262,315.31	273,669.38	262,315.31	273,669.38	3,300,119.16	1,822,005.63
Other Interest Charges						
Customers' Deposits...	109,613.20	109,112.92	109,613.20	109,112.92	1,384,135.27	1,357,132.51
Other Tax Deficiencies..	-	-	-	-	14,000.00	(17,500.00)
Interest on DSM Cost Recovery..	(9,882.18)	1,077.03	(9,882.18)	1,077.03	4,138.31	26,905.51
Interest on Debt to Associated Companies..	94.83	4,617.03	94.83	4,617.03	5,140.89	237,671.14
Other Interest Expense...	86,016.17	42,538.42	86,016.17	42,538.42	1,159,566.75	922,715.47
Total..	185,842.02	157,345.40	185,842.02	157,345.40	2,566,981.22	2,526,924.63
Total Interest..	$ 3,498,676.45	$ 3,727,073.07	$ 3,498,676.45	$ 3,727,073.07	$ 44,431,297.00	$ 47,989,225.18

February 21, 2012

Louisville Gas and Electric 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..	$ 1,545,658.00	$ 1,449,790.00	$ 1,545,658.00	$ 1,449,790.00
Unemployment..	107,426.83	56,297.84	107,426.83	56,297.84
FICA..	802,884.28	630,096.44	802,884.28	630,096.44
Public Service Commission Fee..............................	162,886.60	161,096.90	162,886.60	161,096.90
Federal Income..	7,305,783.95	9,942,013.27	7,305,783.95	9,942,013.27
State Income..	1,333,091.30	1,813,133.12	1,333,091.30	1,813,133.12
Miscellaneous..	3,246.57	7,222.67	3,246.57	7,222.67
Total Charged to Operating Expense..........	11,260,977.53	14,059,650.24	11,260,977.53	14,059,650.24
Taxes Charged to Other Accounts...........................	(4,045,203.32)	253,940.94	(4,045,203.32)	253,940.94
Taxes Accrued on Intercompany Accounts.............	(35,891.25)	(278,231.12)	(35,891.25)	(278,231.12)
Total Taxes Charged...................................	$ 7,179,882.96	$ 14,035,360.06	$ 7,179,882.96	$ 14,035,360.06

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..	$ 11,998,424.82	$ 1,560,217.00	$ 43.38	$ 13,558,598.44
Unemployment..	53,328.91	101,246.77	23,296.72	131,278.96
FICA..	526,035.87	672,022.05	589,528.12	608,529.80
Federal Income..	-	4,387,217.90	-	4,387,217.90
State Income..	-	-	-	-
Kentucky Sales and Use Tax...................................	671,793.23	449,155.46	671,793.23	449,155.46
Miscellaneous..	35,266.73	10,023.78	7,523.78	37,766.73
Totals..	$ 13,284,849.56	$ 7,179,882.96	$ 1,292,185.23	$ 19,172,547.29

February 21, 2012

Louisville Gas and Electric Company
Summary of Utility Plant
January 31, 2012

		Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101	**Utility Plant In Service**						
	Common						
	Common General Plant	$ 157,057,082.39	$ 634,759.40	$ -	$ -	$ 634,759.40	$ 157,691,841.79
	Common Intangible Plant	60,891,162.83	216,668.23	-	-	216,668.23	61,107,831.06
		217,948,245.22	851,427.63	-	-	851,427.63	218,799,672.85
	Electric						
	Electric Distribution	964,513,175.85	5,982,582.52	(474,584.10)	(23.74)	5,507,974.68	970,021,150.53
	Electric General Plant	15,943,111.49	-	-	-	-	15,943,111.49
	Electric Hydro Production	42,535,934.10	-	-	-	-	42,535,934.10
	Electric Intangible Plant	2,240.29	-	-	-	-	2,240.29
	Electric Other Production	234,246,978.99	-	-	-	-	234,246,978.99
	Electric Steam Production	2,114,510,864.74	-	-	-	-	2,114,510,864.74
	Electric Transmission	254,611,190.87	1,050,986.40	(168,683.63)	-	882,302.77	255,493,493.64
		3,626,363,496.33	7,033,568.92	(643,267.73)	(23.74)	6,390,277.45	3,632,753,773.78
	Gas						
	Gas Distribution	592,951,320.42	-	-	-	-	592,951,320.42
	Gas General Plant	8,204,172.47	-	-	-	-	8,204,172.47
	Gas Intangible Plant	387.49	-	-	-	-	387.49
	Gas Storage	80,580,078.39	-	-	-	-	80,580,078.39
	Gas Transmission	21,541,957.36	-	-	-	-	21,541,957.36
		703,277,916.13	-	-	-	-	703,277,916.13
	Total 101 Accounts	4,547,589,657.68	7,884,996.55	(643,267.73)	(23.74)	7,241,705.08	4,554,831,362.76
105	**Plant Held For Future Use**						
	Electric						
	Electric Distribution	649,014.48	-	-	-	-	649,014.48
	Electric Steam Production	-	-	-	-	-	-
		649,014.48	-	-	-	-	649,014.48
	Total 105001	$ 649,014.48	$ -	$ -	$ -	$ -	$ 649,014.48

February 21, 2012

Louisville Gas and Electric Company
Summary of Utility Plant
January 31, 2012

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
106 **Completed Construction Not Classified**						
Common						
Common General Plant..	$ 2,574,936.01	$ (514,311.43)	$ -	$ -	$ (514,311.43)	$ 2,060,624.58
Common Intangible Plant......................................	2,240,884.26	2,704,971.69	-	-	2,704,971.69	4,945,855.95
	4,815,820.27	2,190,660.26	-	-	2,190,660.26	7,006,480.53
Electric						
Electric Distribution...	23,212,235.54	18,196,973.85	-	-	18,196,973.85	41,409,209.39
Electric General Plant..	6,763.22	-	-	-	-	6,763.22
Electric Hydro Production.....................................	16,456.36	-	-	-	-	16,456.36
Electric Intangible Plant...	-	-	-	-	-	-
Electric Other Production......................................	3,535,959.74	153,975.46	-	-	153,975.46	3,689,935.20
Electric Steam Production......................................	41,241,674.58	2,803,964.22	-	-	2,803,964.22	44,045,638.80
Electric Transmission...	37,708,783.02	2,859,211.82	-	-	2,859,211.82	40,567,994.84
	105,721,872.46	24,014,125.35	-	-	24,014,125.35	129,735,997.81
Gas						
Gas Distribution...	18,865,984.48	1,123,540.31	-	-	1,123,540.31	19,989,524.79
Gas General Plant..	263,073.78	49,134.31	-	-	49,134.31	312,208.09
Gas Intangible Plant...	-	-	-	-	-	-
Gas Storage..	514,613.00	5,411,795.60	-	-	5,411,795.60	5,926,408.60
Gas Transmission...	1,459,528.03	2,072.08	-	-	2,072.08	1,461,600.11
	21,103,199.29	6,586,542.30	-	-	6,586,542.30	27,689,741.59
Total 106 Accounts	131,640,892.02	32,791,327.91	-	-	32,791,327.91	164,432,219.93
117 **Gas Stored Underground-Noncurrent**						
Gas						
Gas Stored Nonrecoverable..................................	2,139,990.00	-	-	-	-	2,139,990.00
	2,139,990.00	-	-	-	-	2,139,990.00
Total 117001	2,139,990.00	-	-	-	-	2,139,990.00
121 **Nonutility Property**						
Common						
Non Utility Property..	75,239.56	-	-	-	-	75,239.56
	75,239.56	-	-	-	-	75,239.56
Total 121001	75,239.56	-	-	-	-	75,239.56
107 **Construction Work In Progress**						
Common..	15,083,939.33	(2,443,132.63)	-	-	(2,443,132.63)	12,640,806.70
Electric..	152,710,828.07	(22,863,816.83)	-	-	(22,863,816.83)	129,847,011.24
Gas..	47,481,609.94	(2,965,465.23)	-	-	(2,965,465.23)	44,516,144.71
	215,276,377.34	(28,272,414.69)	-	-	(28,272,414.69)	187,003,962.65
Total Plant (Non-CWIP)......................................	4,682,094,793.74	40,676,324.46	(643,267.73)	(23.74)	40,033,032.99	4,722,127,826.73
Total Plant + CWIP..	4,897,371,171.08	12,403,909.77	(643,267.73)	(23.74)	11,760,618.30	4,909,131,789.38
Total Plant + CWIP - Non Utility..........................	$ 4,897,295,931.52	$ 12,403,909.77	$ (643,267.73)	$ (23.74)	$ 11,760,618.30	$ 4,909,056,549.82

February 21, 2012

Louisville Gas and Electric 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										
Common General Plant	$ (77,087,119.39)	$ (1,001,870.55)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (78,088,989.94)
Common General Plant - ARO	(2,403.59)	(171.70)	-	-	-	-	-	-	-	(2,575.29)
Electric Distribution	(287,667,187.72)	(1,500,857.99)	474,584.10	-	-	-	-	-	-	(288,693,461.61)
Electric Distribution - ARO	(7,290.40)	(949.92)	-	(223.56)	-	-	-	-	-	(8,463.88)
Electric General Plant	(11,305,192.13)	(44,957.37)	-	-	-	-	-	-	-	(11,350,149.50)
Electric Hydro Production	(10,051,997.22)	(47,156.37)	-	-	-	-	-	-	-	(10,099,153.59)
Electric Hydro Production - ARO	(2,112.62)	(145.71)	-	-	-	-	-	-	-	(2,258.33)
Electric Other Production	(67,466,740.67)	(699,057.56)	-	-	-	-	-	-	-	(68,165,798.23)
Electric Other Production - ARO	(1,302.82)	(96.56)	-	-	-	-	-	-	-	(1,399.38)
Electric Steam Production	(1,060,614,162.86)	(4,784,443.99)	-	-	-	-	-	-	-	(1,065,398,606.85)
Electric Steam Production - ARO	(1,402,047.92)	(155,611.30)	-	-	-	-	-	-	-	(1,557,659.22)
Electric Transmission	(121,989,304.84)	(373,405.64)	168,683.63	-	-	-	-	-	-	(122,194,026.85)
Electric Transmission - ARO	(903.28)	(679.61)	-	-	-	-	-	-	-	(1,582.89)
Gas Distribution	(131,835,425.42)	(1,006,201.55)	-	-	-	-	-	-	-	(132,841,626.97)
Gas Distribution - ARO	(346,237.51)	(24,728.63)	-	-	-	-	-	-	-	(370,966.14)
Gas General Plant	(5,044,235.87)	(29,678.06)	-	-	-	-	-	-	-	(5,073,913.93)
Gas Storage	(31,071,784.79)	(97,383.66)	-	-	-	-	-	-	-	(31,169,168.45)
Gas Storage - ARO	(257,551.24)	(18,348.45)	-	-	-	-	-	-	-	(275,899.69)
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(9,486,356.38)	(5,073.74)	-	-	-	-	-	-	-	(9,491,430.12)
Gas Transmission - ARO	(35,270.86)	(8,817.73)	-	-	-	-	-	-	-	(44,088.59)
Non Utility Property	(63,360.36)	-	-	-	-	-	-	-	-	(63,360.36)
	(1,815,737,987.89)	(9,799,636.09)	643,267.73	(223.56)	-	-	-	-	-	(1,824,894,579.81)
Cost Of Removal										
Common General Plant	(637,762.44)	(24,020.41)	-	-	-	-	-	-	-	(661,782.85)
Electric Distribution	(148,949,763.17)	(595,835.92)	-	-	-	-	667,622.24	-	-	(148,877,976.85)
Electric General Plant	3,866.64	-	-	-	-	-	-	-	-	3,866.64
Electric Hydro Production	732,455.11	(3,579.36)	-	-	-	-	-	-	-	728,875.75
Electric Other Production	(2,535,958.71)	(29,974.93)	-	-	-	-	-	-	-	(2,565,933.64)
Electric Steam Production	(108,291,391.50)	(1,433,399.12)	-	-	-	-	-	-	-	(109,724,790.62)
Electric Transmission	(25,759,724.87)	(120,388.15)	-	-	-	-	163,887.84	-	-	(25,716,225.18)
Gas Distribution	(62,001,399.83)	(283,700.30)	-	-	-	-	-	-	-	(62,285,100.13)
Gas General Plant	(0.02)	-	-	-	-	-	-	-	-	(0.02)
Gas Storage	262,470.54	(12,660.21)	-	-	-	-	-	-	-	249,810.33
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(2,984,857.77)	(1,256.02)	-	-	-	-	-	-	-	(2,986,113.79)
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	$ (350,162,066.02)	$ (2,504,814.42)	$ -	$ -	$ -	$ -	$ 831,510.08	$ -	$ -	$ (351,835,370.36)

February 21, 2012

Louisville Gas and Electric 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
Salvage										
Common General Plant	$ 278,457.83	$ 31.94	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 278,489.77
Electric Distribution	18,531,222.48	121,366.96	-	-	-	-	-	(31,445.83)	-	18,621,143.61
Electric General Plant	140,589.22	187.29	-	-	-	-	-	-	-	140,776.51
Electric Hydro Production	376,638.17	-	-	-	-	-	-	-	-	376,638.17
Electric Other Production	(18,998.67)	-	-	-	-	-	-	-	-	(18,998.67)
Electric Steam Production	24,020,678.65	170,641.05	-	-	-	-	-	-	-	24,191,319.70
Electric Transmission	6,511,015.77	22,280.58	-	-	-	-	-	-	-	6,533,296.35
Gas Distribution	3,791,455.11	16,879.52	-	-	-	-	-	-	-	3,808,334.63
Gas General Plant	228,159.61	240.20	-	-	-	-	-	-	-	228,399.81
Gas Storage	287,152.21	1,475.22	-	-	-	-	-	-	-	288,627.43
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	223,309.53	471.01	-	-	-	-	-	-	-	223,780.54
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	54,369,679.91	333,573.77	-	-	-	-	-	(31,445.83)	-	54,671,807.85
Total Reserves										
Common	(77,512,187.95)	(1,026,030.72)	-	-	-	-	-	-	-	(78,538,218.67)
Electric	(1,795,747,613.36)	(9,476,063.62)	643,267.73	(223.56)	-	-	831,510.08	(31,445.83)	-	(1,803,780,568.56)
Gas	(238,270,572.69)	(1,468,782.40)	-	-	-	-	-	-	-	(239,739,355.09)
	(2,111,530,374.00)	(11,970,876.74)	643,267.73	(223.56)	-	-	831,510.08	(31,445.83)	-	(2,122,058,142.32)
Retirement Work In Progress										
Common	149,762.35	-	-	-	-	-	(29,284.35)	(10,496.95)	-	109,981.05
Electric	11,924,715.03	-	-	-	-	(800,064.25)	506,473.47	(13,165.93)	(75,896.49)	11,542,061.83
Gas	1,590,687.78	-	-	-	-	-	59,700.99	-	-	1,650,388.77
	13,665,165.16	-	-	-	-	(800,064.25)	536,890.11	(23,662.88)	(75,896.49)	13,302,431.65
YTD ACTIVITY	(2,097,865,208.84)	(11,970,876.74)	643,267.73	(223.56)	-	(800,064.25)	1,368,400.19	(55,108.71)	(75,896.49)	(2,108,755,710.67)
Amortization										
Common	(20,071,604.03)	(705,817.58)	-	-	-	-	-	-	-	(20,777,421.61)
Electric	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-
AMORTIZATION TOTAL	(20,071,604.03)	(705,817.58)	-	-	-	-	-	-	-	(20,777,421.61)
Depreciation & Amortization Total	$ (2,117,936,812.87)	$ (12,676,694.32)	$ 643,267.73	$ (223.56)	$ -	$ (800,064.25)	$ 1,368,400.19	$ (55,108.71)	$ (75,896.49)	$ (2,129,533,132.28)
Depr & Amort - Nonutility for Balance Sheet										(2,129,469,771.92)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)	$ 2,779,422,479.01									$ 2,779,586,777.90

February 21, 2012

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
January 31, 2012

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues.......................................	$ 88,120,737.69	$ -	$ 88,120,737.69
Gas Operating Revenues...	47,499,975.80	-	47,499,975.80
Total Operating Revenues..	135,620,713.49	-	135,620,713.49
Fuel for Electric Generation..	33,830,887.72	-	33,830,887.72
Power Purchased...	5,288,971.86	-	5,288,971.86
Gas Supply Expenses..	27,992,187.24	-	27,992,187.24
Other Operation Expenses...	19,790,408.88	-	19,790,408.88
Maintenance..	7,962,500.39	-	7,962,500.39
Depreciation..	11,920,225.38	-	11,920,225.38
Amortization Expense...	705,817.58	-	705,817.58
Regulatory Credits...	(450,370.70)	-	(450,370.70)
Taxes			
Federal Income...	7,305,783.95	-	7,305,783.95
State Income..	1,333,091.30	-	1,333,091.30
Deferred Federal Income - Net.................................	76,149.99	8,230.80	84,380.79
Deferred State Income - Net.....................................	-	1,501.06	1,501.06
Property and Other...	2,622,102.28	-	2,622,102.28
Amortization of Investment Tax Credit....................	(223,356.00)	-	(223,356.00)
Loss (Gain) from Disposition of Allowances...............	-	-	-
Accretion Expense..	240,821.09	-	240,821.09
Total Operating Expenses..	118,395,220.96	9,731.86	118,404,952.82
Net Operating Income...	17,225,492.53	(9,731.86)	17,215,760.67
Other Income Less Deductions.................................	(164,729.07)	-	(164,729.07)
Income Before Interest Charges................................	17,060,763.46	(9,731.86)	17,051,031.60
Interest on Long-Term Debt..	3,050,519.12	(25,017.63)	3,025,501.49
Amortization of Debt Expense - Net...........................	262,315.31	-	262,315.31
Other Interest Expenses...	185,842.02	-	185,842.02
Total Interest Charges..	3,498,676.45	(25,017.63)	3,473,658.82
Net Income..	$ 13,562,087.01	$ 15,285.77	$ 13,577,372.78

February 21, 2012

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
January 31, 2012

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues..	$ 88,120,737.69	$ -	$ 88,120,737.69
Gas Operating Revenues..	47,499,975.80	-	47,499,975.80
Total Operating Revenues...	135,620,713.49	-	135,620,713.49
Fuel for Electric Generation...	33,830,887.72	-	33,830,887.72
Power Purchased..	5,288,971.86	-	5,288,971.86
Gas Supply Expenses...	27,992,187.24	-	27,992,187.24
Other Operation Expenses...	19,790,408.88	-	19,790,408.88
Maintenance..	7,962,500.39	-	7,962,500.39
Depreciation..	11,920,225.38	-	11,920,225.38
Amortization Expense..	705,817.58	-	705,817.58
Regulatory Credits...	(450,370.70)	-	(450,370.70)
Taxes			
Federal Income..	7,305,783.95	-	7,305,783.95
State Income...	1,333,091.30	-	1,333,091.30
Deferred Federal Income - Net..................................	76,149.99	8,230.80	84,380.79
Deferred State Income - Net.....................................	-	1,501.06	1,501.06
Property and Other..	2,622,102.28	-	2,622,102.28
Amortization of Investment Tax Credit.....................	(223,356.00)	-	(223,356.00)
Loss (Gain) from Disposition of Allowances................	-	-	-
Accretion Expense...	240,821.09	-	240,821.09
Total Operating Expenses...	118,395,220.96	9,731.86	118,404,952.82
Net Operating Income..	17,225,492.53	(9,731.86)	17,215,760.67
Other Income Less Deductions.................................	(164,729.07)	-	(164,729.07)
Income Before Interest Charges................................	17,060,763.46	(9,731.86)	17,051,031.60
Interest on Long-Term Debt...	3,050,519.12	(25,017.63)	3,025,501.49
Amortization of Debt Expense - Net............................	262,315.31	-	262,315.31
Other Interest Expenses...	185,842.02	-	185,842.02
Total Interest Charges...	3,498,676.45	(25,017.63)	3,473,658.82
Net Income...	$ 13,562,087.01	$ 15,285.77	$ 13,577,372.78

February 21, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
January 31, 2012

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period………………………………	$ 868,929,557.39	$ 827,993,251.96	$ (808,732,890.73)	$ (808,899,282.44)	$ 60,196,666.66	$ 19,093,969.52
Add:						
Net Income (Loss) for Period…………………………	13,562,087.01	18,912,171.82	15,285.77	528,169.77	13,577,372.78	19,440,341.59
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	-	-	-	-	-	-
Balance at End of Period…………………………………	$ 882,491,644.40	$ 846,905,423.78	$ (808,717,604.96)	$ (808,371,112.67)	$ 73,774,039.44	$ 38,534,311.11

February 21, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
January 31, 2012

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period…………………………….	$ 868,929,557.39	$ 827,993,251.96	$ (808,732,890.73)	$ (808,899,282.44)	$ 60,196,666.66	$ 19,093,969.52
Add:						
Net Income (Loss) for Period…………………………	13,562,087.01	18,912,171.82	15,285.77	528,169.77	13,577,372.78	19,440,341.59
Deduct:						
Adjustment to Retained Earnings…………………….	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	-	-	-	-	-	-
Balance at End of Period………………………………….	$ 882,491,644.40	$ 846,905,423.78	$ (808,717,604.96)	$ (808,371,112.67)	$ 73,774,039.44	$ 38,534,311.11

February 21, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
January 31, 2012

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period…………………………	$ 846,905,423.78	$ 764,289,058.43	$ (808,371,112.67)	$ -	$ 38,534,311.11	$ 764,289,058.43
Add:						
Net Income (Loss) for Period………………………	118,836,220.62	137,616,365.35	(346,492.29)	575,778.85	118,489,728.33	138,192,144.20
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	808,946,891.52	-	808,946,891.52
Common Dividends						
Common Stock Without Par Value………………	83,250,000.00	55,000,000.00	-	-	83,250,000.00	55,000,000.00
Balance at End of Period…………………………………	$ 882,491,644.40	$ 846,905,423.78	$ (808,717,604.96)	$ (808,371,112.67)	$ 73,774,039.44	$ 38,534,311.11

February 21, 2012

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of January 31, 2012

Assets	Without Purchase Accounting	Purchase Accounting	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 4,909,056,549.82	$ -	$ 4,909,056,549.82
Less: Reserves for Depreciation and Amortization....	2,129,469,771.92	-	2,129,469,771.92
Total..	2,779,586,777.90	-	2,779,586,777.90
Investments			
Ohio Valley Electric Corporation.............................	594,286.00	-	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	-	11,879.20
Special Funds...	29,788,557.01	-	29,788,557.01
Total..	30,394,722.21	-	30,394,722.21
Current and Accrued Assets			
Cash..	22,562,167.83	-	22,562,167.83
Special Deposits...	12,277.00	-	12,277.00
Temporary Cash Investments...................................	33,199.87	-	33,199.87
Accounts Receivable - Less Reserve.........................	143,404,574.12	-	143,404,574.12
Accounts Receivable from Associated Companies....	12,419,799.02	-	12,419,799.02
Materials and Supplies - At Average Cost			
Fuel..	50,199,426.27	-	50,199,426.27
Plant Materials and Operating Supplies.................	30,878,565.61	-	30,878,565.61
Stores Expense...	5,639,880.99	-	5,639,880.99
Gas Stored Underground.......................................	41,005,070.14	-	41,005,070.14
Emission Allowances...	19,936.74	-	19,936.74
Prepayments..	5,317,036.50	-	5,317,036.50
Miscellaneous Current and Accrued Assets..............	-	-	-
Total..	311,491,934.09	-	311,491,934.09
Deferred Debits and Other			
Unamortized Debt Expense......................................	13,189,647.53	(3,465,633.84)	9,724,013.69
Unamortized Loss on Bonds....................................	20,885,609.22	-	20,885,609.22
Accumulated Deferred Income Taxes.......................	23,749,922.01	67,074,595.36	90,824,517.37
Deferred Regulatory Assets.....................................	399,361,510.17	8,711,900.31	408,073,410.48
Other Deferred Debits..	1,259,355.16	158,776,903.92	160,036,259.08
Goodwill..	-	389,157,351.59	389,157,351.59
Total..	458,446,044.09	620,255,117.34	1,078,701,161.43
Total Assets..	$ 3,579,919,478.29	$ 620,255,117.34	$ 4,200,174,595.63

February 21, 2012

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of January 31, 2012

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting	Total
Proprietary Capital			
Common Stock...	$ 425,170,424.09	$ -	$ 425,170,424.09
Less: Common Stock Expense......................................	835,888.64	-	835,888.64
Paid-In Capital...	83,581,499.00	1,194,085,869.02	1,277,667,368.02
Other Comprehensive Income.......................................	-	-	-
Retained Earnings..	882,491,644.40	(808,717,604.96)	73,774,039.44
Total Proprietary Capital...	1,390,407,678.85	385,368,264.06	1,775,775,942.91
Pollution Control Bonds - Net of Reacquired Bonds.....	574,304,000.00	6,201,452.55	580,505,452.55
First Mortgage Bonds..	531,354,864.10	-	531,354,864.10
LT Notes Payable to Associated Companies................	-	-	-
Total Long-Term Debt...	1,105,658,864.10	6,201,452.55	1,111,860,316.65
Total Capitalization...	2,496,066,542.95	391,569,716.61	2,887,636,259.56
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies.................	-	-	-
Accounts Payable...	90,067,704.18	-	90,067,704.18
Accounts Payable to Associated Companies................	15,168,942.65	-	15,168,942.65
Customer Deposits...	22,478,501.90	-	22,478,501.90
Taxes Accrued...	19,172,547.29	-	19,172,547.29
Interest Accrued...	8,169,288.22	-	8,169,288.22
Miscellaneous Current and Accrued Liabilities............	27,349,223.25	-	27,349,223.25
Total..	182,406,207.49	-	182,406,207.49
Deferred Credits and Other			
Accumulated Deferred Income Taxes...........................	499,655,847.55	64,662,230.34	564,318,077.89
Investment Tax Credit...	42,495,488.13	-	42,495,488.13
Regulatory Liabilities...	60,785,846.15	158,776,903.92	219,562,750.07
Customer Advances for Construction...........................	7,319,187.89	-	7,319,187.89
Asset Retirement Obligations..	58,847,147.60	-	58,847,147.60
Other Deferred Credits..	8,612,478.80	5,246,266.47	13,858,745.27
Miscellaneous Long-Term Liabilities...........................	61,995,072.79	-	61,995,072.79
Misc Long-Term Liab Due to Assoc Cos......................	-	-	-
Accum Provision for Postretirement Benefits................	161,735,658.94	-	161,735,658.94
Total..	901,446,727.85	228,685,400.73	1,130,132,128.58
Total Liabilities and Stockholders' Equity..........................	$ 3,579,919,478.29	$ 620,255,117.34	$ 4,200,174,595.63

February 21, 2012

LOUISVILLE GAS AND ELECTRIC COMPANY

Financial Reports

December 31, 2011

Index
Financial and Operating Reports

Louisville Gas and Electric 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.

Louisville Gas and Electric Company
Comparative Statement of Income
December 31, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 84,801,954.82	$ 93,751,447.34	$ (8,949,492.52)	(9.55)
Gas Operating Revenues..	41,094,658.46	57,294,231.67	(16,199,573.21)	(28.27)
Total Operating Revenues..	125,896,613.28	151,045,679.01	(25,149,065.73)	(16.65)
Fuel for Electric Generation..	32,429,492.43	34,495,080.08	(2,065,587.65)	(5.99)
Power Purchased..	6,940,294.11	4,790,428.59	2,149,865.52	44.88
Gas Supply Expenses..	20,934,175.22	38,001,070.70	(17,066,895.48)	(44.91)
Other Operation Expenses..	19,759,510.34	18,711,551.25	1,047,959.09	5.60
Maintenance..	8,933,526.92	14,961,040.90	(6,027,513.98)	(40.29)
Depreciation..	11,888,245.80	10,994,061.68	894,184.12	8.13
Amortization Expense...	699,391.68	634,111.82	65,279.86	10.29
Regulatory Credits..	(437,110.01)	(409,343.52)	(27,766.49)	(6.78)
Taxes				
Federal Income...	(7,561,185.42)	(6,078,915.85)	(1,482,269.57)	(24.38)
State Income...	(968,373.77)	226,424.99	(1,194,798.76)	(527.68)
Deferred Federal Income - Net..................................	13,652,179.03	13,181,597.26	470,581.77	3.57
Deferred State Income - Net......................................	1,868,150.81	1,002,926.16	865,224.65	86.27
Property and Other..	2,438,036.55	1,669,312.60	768,723.95	46.05
Amortization of Investment Tax Credit.....................	(236,025.00)	(208,481.00)	(27,544.00)	(13.21)
Loss (Gain) from Disposition of Allowances...............	-	-	-	-
Accretion Expense..	231,701.50	217,727.10	13,974.40	6.42
Total Operating Expenses..	110,572,010.19	132,188,592.76	(21,616,582.57)	(16.35)
Net Operating Income..	15,324,603.09	18,857,086.25	(3,532,483.16)	(18.73)
Other Income Less Deductions..................................	419,450.96	(877,689.81)	1,297,140.77	147.79
Income Before Interest Charges................................	15,744,054.05	17,979,396.44	(2,235,342.39)	(12.43)
Interest on Long-Term Debt..	3,156,393.86	3,393,711.56	(237,317.70)	(6.99)
Amortization of Debt Expense - Net.............................	262,183.81	271,039.07	(8,855.26)	(3.27)
Other Interest Expenses..	172,424.54	274,450.19	(102,025.65)	(37.17)
Total Interest Charges..	3,591,002.21	3,939,200.82	(348,198.61)	(8.84)
Net Income..	$ 12,153,051.84	$ 14,040,195.62	$ (1,887,143.78)	(13.44)

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Louisville Gas and Electric Company
Comparative Statement of Income
December 31, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 1,059,750,303.49	$ 1,015,611,566.97	$ 44,138,736.52	4.35
Gas Operating Revenues..	304,574,421.82	302,947,355.88	1,627,065.94	0.54
Total Operating Revenues..	1,364,324,725.31	1,318,558,922.85	45,765,802.46	3.47
Fuel for Electric Generation..	360,968,393.36	368,556,326.34	(7,587,932.98)	(2.06)
Power Purchased...	74,894,547.12	54,379,718.69	20,514,828.43	37.73
Gas Supply Expenses..	161,235,625.70	169,003,608.05	(7,767,982.35)	(4.60)
Other Operation Expenses...	236,277,354.89	226,813,004.57	9,464,350.32	4.17
Maintenance...	116,359,068.55	111,701,105.08	4,657,963.47	4.17
Depreciation...	141,998,214.92	131,210,003.27	10,788,211.65	8.22
Amortization Expense...	8,133,464.03	7,726,988.90	406,475.13	5.26
Regulatory Credits..	(5,730,085.69)	(4,269,731.45)	(1,460,354.24)	(34.20)
Taxes				
Federal Income...	11,962,850.45	28,874,607.18	(16,911,756.73)	(58.57)
State Income..	8,265,532.67	6,047,167.43	2,218,365.24	36.68
Deferred Federal Income - Net...................................	52,223,724.36	27,667,005.00	24,556,719.36	88.76
Deferred State Income - Net.......................................	2,011,675.35	2,370,024.44	(358,349.09)	(15.12)
Property and Other...	28,121,583.64	22,571,623.82	5,549,959.82	24.59
Amortization of Investment Tax Credit.....................	(2,805,732.00)	(2,501,774.00)	(303,958.00)	(12.15)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	2,644,484.62	3,284,105.63	(639,621.01)	(19.48)
Total Operating Expenses..	1,196,558,124.03	1,153,399,322.81	43,158,801.22	3.74
Net Operating Income...	167,766,601.28	165,159,600.04	2,607,001.24	1.58
Other Income Less Deductions..................................	1,079,397.77	10,717,472.34	(9,638,074.57)	(89.93)
Income Before Interest Charges.................................	168,845,999.05	175,877,072.38	(7,031,073.33)	(4.00)
Interest on Long-Term Debt..	38,809,735.79	43,895,047.17	(5,085,311.38)	(11.59)
Amortization of Debt Expense - Net.............................	3,311,473.23	1,664,625.74	1,646,847.49	98.93
Other Interest Expenses...	2,538,484.60	2,603,013.75	(64,529.15)	(2.48)
Total Interest Charges..	44,659,693.62	48,162,686.66	(3,502,993.04)	(7.27)
Net Income..	$ 124,186,305.43	$ 127,714,385.72	$ (3,528,080.29)	(2.76)

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Louisville Gas and Electric 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..	$ 1,059,750,303.49	$ 1,015,611,566.97	$ 44,138,736.52	4.35
Gas Operating Revenues...	304,574,421.82	302,947,355.88	1,627,065.94	0.54
Total Operating Revenues..	1,364,324,725.31	1,318,558,922.85	45,765,802.46	3.47
Fuel for Electric Generation..	360,968,393.36	368,556,326.34	(7,587,932.98)	(2.06)
Power Purchased...	74,894,547.12	54,379,718.69	20,514,828.43	37.73
Gas Supply Expenses..	161,235,625.70	169,003,608.05	(7,767,982.35)	(4.60)
Other Operation Expenses...	236,277,354.89	226,813,004.57	9,464,350.32	4.17
Maintenance..	116,359,068.55	111,701,105.08	4,657,963.47	4.17
Depreciation...	141,998,214.92	131,210,003.27	10,788,211.65	8.22
Amortization Expense...	8,133,464.03	7,726,988.90	406,475.13	5.26
Regulatory Credits..	(5,730,085.69)	(4,269,731.45)	(1,460,354.24)	(34.20)
Taxes				
Federal Income..	11,962,850.45	28,874,607.18	(16,911,756.73)	(58.57)
State Income...	8,265,532.67	6,047,167.43	2,218,365.24	36.68
Deferred Federal Income - Net...................................	52,223,724.36	27,667,005.00	24,556,719.36	88.76
Deferred State Income - Net.......................................	2,011,675.35	2,370,024.44	(358,349.09)	(15.12)
Property and Other...	28,121,583.64	22,571,623.82	5,549,959.82	24.59
Amortization of Investment Tax Credit.....................	(2,805,732.00)	(2,501,774.00)	(303,958.00)	(12.15)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	2,644,484.62	3,284,105.63	(639,621.01)	(19.48)
Total Operating Expenses..	1,196,558,124.03	1,153,399,322.81	43,158,801.22	3.74
Net Operating Income...	167,766,601.28	165,159,600.04	2,607,001.24	1.58
Other Income Less Deductions..................................	1,079,397.77	10,717,472.34	(9,638,074.57)	(89.93)
Income Before Interest Charges.................................	168,845,999.05	175,877,072.38	(7,031,073.33)	(4.00)
Interest on Long-Term Debt..	38,809,735.79	43,895,047.17	(5,085,311.38)	(11.59)
Amortization of Debt Expense - Net.............................	3,311,473.23	1,664,625.74	1,646,847.49	98.93
Other Interest Expenses...	2,538,484.60	2,603,013.75	(64,529.15)	(2.48)
Total Interest Charges..	44,659,693.62	48,162,686.66	(3,502,993.04)	(7.27)
Net Income..	$ 124,186,305.43	$ 127,714,385.72	$ (3,528,080.29)	(2.76)

January 26, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings
December 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period..	$ 856,776,505.55	$ 813,953,056.34	$ 827,993,251.96	$ 755,278,866.24	$ 827,993,251.96	$ 755,278,866.24
Add:						
Net Income for Period..	12,153,051.84	14,040,195.62	124,186,305.43	127,714,385.72	124,186,305.43	127,714,385.72
Deduct:						
Common Dividends						
Common Stock Without Par Value.....................	-	-	83,250,000.00	55,000,000.00	83,250,000.00	55,000,000.00
Balance at End of Period..	$ 868,929,557.39	$ 827,993,251.96	$ 868,929,557.39	$ 827,993,251.96	$ 868,929,557.39	$ 827,993,251.96

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Louisville Gas and Electric Company
Comparative Balance Sheets as of December 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,897,295,931.52	$ 4,748,839,654.01
Less: Reserves for Depreciation and Amortization	2,117,873,452.51	2,043,099,789.34
Total	2,779,422,479.01	2,705,739,864.67
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	28,846,730.20	18,763,173.33
Total	29,452,895.40	19,369,338.53
Current and Accrued Assets		
Cash	24,920,484.53	2,025,606.25
Special Deposits	12,277.00	3,511,014.88
Temporary Cash Investments	33,063.99	100,405.59
Accounts Receivable - Less Reserve	137,419,594.66	163,630,222.30
Accounts Receivable from Associated Companies	10,916,898.01	29,799,791.23
Materials and Supplies - At Average Cost		
Fuel	52,502,546.26	68,043,290.05
Plant Materials and Operating Supplies	30,625,941.68	29,326,915.51
Stores Expense	5,596,505.54	4,943,153.44
Gas Stored Underground	53,287,604.59	59,956,180.78
Emission Allowances	2,511.67	2,728.96
Prepayments	5,472,353.44	6,832,694.11
Miscellaneous Current and Accrued Assets	-	137,908.13
Total	320,789,781.37	368,309,911.23
Deferred Debits and Other		
Unamortized Debt Expense	13,326,195.59	13,116,651.27
Unamortized Loss on Bonds	20,963,862.78	21,934,649.45
Accumulated Deferred Income Taxes	23,826,072.01	38,744,526.28
Deferred Regulatory Assets	397,110,901.24	344,036,363.17
Other Deferred Debits	1,480,708.22	1,127,060.49
Total	456,707,739.84	418,959,250.66
Total Assets	$ 3,586,372,895.62	$ 3,512,378,365.09

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	868,929,557.39	827,993,251.96
Total Proprietary Capital	1,376,845,591.84	1,335,909,286.41
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds	531,331,542.44	531,051,682.50
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,105,635,542.44	942,155,682.50
Total Capitalization	2,482,481,134.28	2,278,064,968.91
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	11,876,000.00
Notes Payable	-	163,000,000.00
Accounts Payable	97,848,807.56	104,974,357.13
Accounts Payable to Associated Companies	25,528,425.55	19,944,791.03
Customer Deposits	22,361,041.85	23,237,608.55
Taxes Accrued	13,284,849.56	9,598,152.76
Interest Accrued	5,825,755.42	5,235,853.08
Miscellaneous Current and Accrued Liabilities	22,176,210.30	24,850,419.60
Total	187,025,090.24	362,717,182.15
Deferred Credits and Other		
Accumulated Deferred Income Taxes	499,655,847.56	458,393,362.16
Investment Tax Credit	42,718,844.13	45,524,576.13
Regulatory Liabilities	58,617,596.40	51,426,348.46
Customer Advances for Construction	7,307,168.56	8,580,930.08
Asset Retirement Obligations	58,606,350.25	52,650,788.91
Other Deferred Credits	5,120,367.14	5,677,069.75
Miscellaneous Long-Term Liabilities	60,707,001.86	35,751,188.04
Accum Provision for Postretirement Benefits	184,133,495.20	213,591,950.50
Total	916,866,671.10	871,596,214.03
Total Liabilities and Stockholders' Equity	$ 3,586,372,895.62	$ 3,512,378,365.09

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Louisville Gas and Electric 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..	75,000,000	21,294,223	$ 425,170,424.09	
Less: Common Stock Expense..			835,888.64	
Paid-In Capital..			83,581,499.00	
Other Comprehensive Income..			-	
Retained Earnings..			868,929,557.39	
Total Proprietary Capital..			1,376,845,591.84	55.46
Long-Term Debt				
Pollution Control Bonds...				
Jefferson County 2000 Series A due 05/01/27 5.375%................			25,000,000.00	
Trimble County 2000 Series A due 08/01/30 Var%......................			83,335,000.00	
Jefferson County 2001 Series A due 09/01/26 Var%..................			22,500,000.00	
Jefferson County 2001 Series A due 09/01/27 Var%...................			10,104,000.00	
Jefferson County 2001 Series B due 11/01/27 Var%..................			35,000,000.00	
Trimble County 2001 Series A due 09/01/26 Var%......................			27,500,000.00	
Trimble County 2001 Series A due 10/01/32 Var%......................			41,665,000.00	
Trimble County 2001 Series B due 11/01/27 Var%......................			35,000,000.00	
Louisville Metro 2003 Series A due 10/01/33 1.900%.................			128,000,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%.................			40,000,000.00	
Louisville Metro 2007 Series A due 06/01/33 5.625%.................			31,000,000.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%.................			35,200,000.00	
Trimble County 2007 Series A due 06/01/33 4.600%..................			60,000,000.00	
Total Pollution Control Bonds..			574,304,000.00	23.13
First Mortgage Bonds..				
First Mortgage Bond Due 11/15/15 1.625%..................................			250,000,000.00	
First Mortgage Bond Due 11/15/40 5.125%..................................			285,000,000.00	
Total First Mortgage Bonds..			535,000,000.00	21.56
Less: First Mortgage Bonds Debt Discount.....................................				
First Mortgage Bond Due 11/15/15 1.625%..................................			(683,937.53)	
First Mortgage Bond Due 11/15/40 5.125%..................................			(2,984,520.03)	
			(3,668,457.56)	-0.15
Total First Mortgage Bonds - Net of Debt Discount........................			531,331,542.44	21.41
Total Capitalization..			$ 2,482,481,134.28	100.00

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Louisville Gas and Electric Company
Summary Trial Balance
December 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 4,897,295,931.52	$ 4,897,295,931.52
Reserves for Depreciation and Amortization		(2,117,873,452.51)
Depreciation of Plant		
Electric	(1,783,822,898.33)	
Gas	(236,679,884.91)	
Common	(77,299,065.24)	
Amortization of Plant		
Common	(20,071,604.03)	
Investments		29,452,895.40
Special Funds	28,846,730.20	
Ohio Valley Electric Corporation	594,286.00	
Nonutility Property	11,879.20	
Cash	24,920,484.53	24,920,484.53
Special Deposits		12,277.00
Restricted Cash - Short Term	12,277.00	
Temporary Cash Investments	33,063.99	33,063.99
Accounts Receivable - Less Reserve		137,419,594.66
Unbilled Revenues	64,436,527.09	
Customers - Active	58,965,455.78	
IMPA	3,225,609.95	
IMEA	3,103,454.41	
Income Tax Receivable - Federal	2,830,025.70	
Wholesale Sales	2,363,808.52	
Income Tax Receivable - State	1,398,303.27	
Sundry Accounts Receivable	1,078,348.94	
Transmission Sales	486,917.51	
Damage Claims	476,720.60	
Electricity Swaps	166,354.87	
Other	723,975.36	
Reserves for Uncollectible Accounts		
Utility Customers		
Reserve	(1,398,388.00)	
A/R Miscellaneous	(271,164.47)	
LEM Reserve	(166,354.87)	
Accounts Receivable from Associated Companies		10,916,898.01
LG&E and KU Services/Kentucky Utilities	10,916,898.01	
Fuel		52,502,546.26
Coal 1,067,380.90 Tons @ $48.27; MMBtu 24,033,688.29 @ 214.36¢	51,518,599.61	
Fuel Oil 193,900.34 Gallons @ 263.99¢	511,871.55	
Gas Pipeline 5,100 Mcf @ $92.56	472,075.10	
Plant Materials and Operating Supplies		30,625,941.68
Regular Materials and Supplies	29,804,274.36	
Limestone 92,949.89 Tons @ $8.84	821,667.32	
Stores Expense Undistributed	5,596,505.54	5,596,505.54
Gas Stored Underground - Current		53,287,604.59
Gas Stored Underground* 11,466,101 Mcf (14.73 psia) @ $4.65	53,287,604.59	
Emission Allowances	2,511.67	2,511.67

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Louisville Gas and Electric Company
Summary Trial Balance
December 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Prepayments		$ 5,472,353.44
Insurance	2,700,567.85	
Taxes	977,319.66	
Rights of Way	226,666.71	
Risk Management and Workers Compensation	90,000.00	
Other	1,477,799.22	
Unamortized Debt Expense		13,326,195.59
Trimble County 2000 Series A due 08/01/30 Var%	719,312.04	
Jefferson County 2001 Series A due 09/01/26 Var%	145,548.66	
Jefferson County 2001 Series A due 09/01/27 Var%	319,482.40	
Jefferson County 2001 Series B due 11/01/27 Var%	174,091.46	
Trimble County 2001 Series A due 09/01/26 Var%	158,253.08	
Trimble County 2001 Series B due 11/01/27 Var%	174,120.02	
Trimble County 2002 Series A due 10/01/32 Var%	772,344.33	
Louisville Metro 2003 Series A Due 10/01/33 1.900%	432,531.85	
Louisville Metro 2007 Series B Due 06/01/33 1.900%	166,099.31	
Trimble County 2007 Series A due 06/01/33 4.600%	1,018,028.66	
First Mortgage Bond due 11/15/15 1.625%	2,019,800.08	
First Mortgage Bond due 11/15/40 5.125%	3,442,661.92	
Revolving Credit Agreement	3,783,921.78	
Unamortized Loss on Bonds	20,963,862.78	20,963,862.78
Accumulated Deferred Income Taxes		23,826,072.01
Federal		
Electric	17,653,436.97	
Gas	1,368,281.19	
State		
Electric	4,502,703.92	
Gas	301,649.93	
Regulatory Assets		397,110,901.24
Pension and Postretirement Benefits	225,305,162.00	
Interest Rate Swap Ineffectiveness	59,566,464.10	
2009 Winter Storm	37,627,952.45	
2008 Wind Storm	20,205,452.31	
Deferred Taxes - ASC 740		
Federal		
Electric	12,458,133.70	
State		
Electric	2,272,000.07	
Asset Retirement Obligations		
Electric	9,423,533.13	
Gas	1,233,920.15	
Common	9,106.86	
Swap Termination	8,937,221.78	
2011 Summer Storm	8,052,124.65	
Gas Supply Clause/PBR	5,701,472.15	
Fuel Adjustment Clause	3,598,000.00	
MISO Exit Fee	759,632.70	
Rate Case Expenses	751,749.46	
KCCS Funding	567,067.83	
EKPC FERC Transmission Costs	367,406.80	
CMRG Funding	154,470.00	
General Management Audit	120,031.10	
Other Deferred Debits	1,480,708.22	1,480,708.22
Total Assets	$ 3,586,372,895.62	$ 3,586,372,895.62

* Excludes:		$	Mcf
	Non-recoverable Base Gas	9,648,855.00	7,880,000
	Recoverable Base Gas	2,139,990.00	2,930,000
		11,788,845.00	10,810,000

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Louisville Gas and Electric Company
Summary Trial Balance
December 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 1,376,845,591.84
Common Stock	425,170,424.09	
Less: Common Stock Expense	835,888.64	
Paid-In Capital	83,581,499.00	
Retained Earnings	868,929,557.39	
Pollution Control Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,331,542.44	531,331,542.44
Accounts Payable		97,848,807.56
Regular	90,581,239.26	
Employee Withholdings Payable	5,545,226.10	
Salaries and Wages Accrued	1,722,342.20	
Accounts Payable to Associated Companies		25,528,425.55
LG&E and KU Services/Kentucky Utilities	25,528,425.55	
Customers' Deposits	22,361,041.85	22,361,041.85
Taxes Accrued	13,284,849.56	13,284,849.56
Interest Accrued		5,825,755.42
Jefferson County 2000 Series A due 05/01/27 5.375%	17,895.83	
Trimble County 2000 Series A due 08/01/30 Var%	17,778.13	
Jefferson County 2001 Series A due 09/01/26 Var%	3,698.63	
Jefferson County 2001 Series A due 09/01/27 Var%	67.36	
Jefferson County 2001 Series B due 11/01/27 Var%	11,650.69	
Trimble County 2001 Series A due 09/01/26 Var%	10,193.83	
Trimble County 2001 Series A due 10/01/32 Var%	3,652.82	
Trimble County 2001 Series B due 11/01/27 Var%	11,650.69	
Louisville Metro 2003 Series A due 10/01/33 1.900%	608,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%	951,944.44	
Louisville Metro 2007 Series A due 06/01/33 5.625%	145,312.50	
Louisville Metro 2007 Series B due 06/01/33 1.900%	57,591.11	
Trimble County 2007 Series A due 06/01/33 4.600%	230,000.00	
Interest Rate Swaps	695,186.64	
First Mortgage Bond due 11/15/15 1.625%	519,097.22	
First Mortgage Bond due 11/15/40 5.125%	1,866,354.17	
Customers' Deposits	643,905.89	
Interest Accrued on Tax Liabilities	14,000.00	
Other	17,775.47	
Miscellaneous Current and Accrued Liabilities		22,176,210.30
Vacation Pay Accrued	5,980,227.35	
No-Notice Gas Payable	4,808,672.31	
Derivative Liability - ASC 815	4,550,755.28	
Customer Overpayments	4,191,985.69	
Tax Collections Payable	1,090,154.03	
Home Energy Assistance	511,590.60	
Retirement Income Liability	436,163.62	
Unearned Revenue	390,305.33	
Other	216,356.09	

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Louisville Gas and Electric Company
Summary Trial Balance
December 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Accumulated Deferred Income Taxes		$ 499,655,847.56
Federal		
Electric	350,820,895.44	
Gas	81,862,099.14	
State		
Electric	54,295,012.50	
Gas	12,677,840.48	
Investment Tax Credit		42,718,844.13
Advanced Coal Credit	23,136,534.00	
Job Development Credit		
Electric	19,026,103.98	
Gas	556,206.15	
Regulatory Liabilities		58,617,596.40
Deferred Taxes		
Federal		
Electric	27,503,680.54	
Gas	1,082,516.16	
State		
Electric	15,083,739.54	
Gas	2,461,807.12	
Gas Supply Clause/PBR	5,039,984.33	
DSM Cost Recovery	3,683,375.48	
Asset Retirement Obligations		
Gas	2,149,408.34	
Electric	188,608.63	
MISO Schedule 10 Charges	626,757.60	
Purchased Gas Adjustment - Tennessee Gas	478,531.66	
Environmental Cost Recovery	319,187.00	
Customers' Advances for Construction		7,307,168.56
Line Extensions		
Gas	6,358,367.69	
Electric	936,200.87	
Other	12,600.00	
Asset Retirement Obligations		58,606,350.25
Electric	36,829,095.09	
Gas	21,669,162.12	
Common	108,093.04	
Other Deferred Credits	5,120,367.14	5,120,367.14
Miscellaneous Long-Term Liabilities		60,707,001.86
Long-Term Derivative Liabilities - ASC 815	55,015,708.82	
Workers' Compensation	5,691,293.04	
Accumulated Provision for Benefits		184,133,495.20
Postretirement Benefits - ASC 715	87,027,508.70	
Pension Payable	93,620,496.50	
Post Employment Benefits Payable	3,689,805.00	
Post Employment Medicare Subsidy	(204,315.00)	
Total Liabilities and Stockholders' Equity	$ 3,586,372,895.62	$ 3,586,372,895.62

January 26, 2012

Louisville Gas and Electric Company
Statement of Cash Flows
December 31, 2011

	Year to Date	
	2011	2010
Cash Flows from Operating Activities		
Net income	$ 124,186,305.43	$ 127,714,385.72
Items not requiring (providing) cash currently:		
Depreciation	141,998,214.92	131,210,003.27
Amortization	8,133,464.03	7,726,988.90
Deferred income taxes - net	56,180,939.67	50,457,601.38
Investment tax credit - net	(2,805,732.00)	(2,501,774.00)
Gain on disposal of assets	(69,454.19)	(33,760.40)
Other	22,585,849.87	(15,890,518.03)
Change in receivables	45,243,958.83	3,874,675.81
Change in inventory	20,639,802.14	(12,359,019.98)
Change in allowance inventory	217.29	1,442.04
Change in payables and accrued expenses	30,053,152.44	(56,166,888.97)
Change in regulatory assets	(52,954,506.97)	(24,046,268.46)
Change in regulatory liabilities	7,191,247.94	(33,480,860.12)
Change in other deferred debits	2,718,585.20	1,976,680.21
Change in other deferred credits	(436,232.17)	(2,350,629.16)
Pension and postretirement funding	(70,274,658.00)	(26,813,841.00)
Other	(12,229,993.32)	40,124,768.11
Net cash provided (used) by operating activities	320,161,161.11	189,442,985.32
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(164,665,585.86)	(147,091,035.98)
Gross additions to common utility plant - construction expenditures	(14,380,687.80)	(23,590,289.68)
Change in restricted cash	(9,400,673.73)	-
Proceeds received from sale of property	69,454.19	34,433.85
Change in non-hedging derivatives	-	3,181,184.50
Reissuance of reacquired bonds as Available for Sale debt securities	163,200,000.00	-
Other	(11,759,760.24)	(10,831,604.16)
Net cash provided (used) by investing activities	(36,937,253.44)	(178,297,311.47)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(2,270,370.99)	521,309,251.60
Payments for retirement of long-term debt	-	(485,000,000.00)
Net change in short-term debt	(174,876,000.00)	4,475,600.00
Dividends on common stock	(83,250,000.00)	(55,000,000.00)
Net cash provided (used) by financing activities	(260,396,370.99)	(14,215,148.40)
Net Increase (Decrease) in Cash and Cash Equivalents	22,827,536.68	(3,069,474.54)
Cash and Cash Equivalents at Beginning of Period	2,126,011.84	5,195,486.38
Cash and Cash Equivalents at End of Period	$ 24,953,548.52	$ 2,126,011.84

January 26, 2012

Louisville Gas and Electric 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						
Jefferson County 2000 Series A due 05/01/27 5.375%.......................	$ 17,895.82	$ 111,979.17	$ 1,249,666.70	$ 1,343,749.92	$ 1,249,666.70	$ 1,343,749.92
Trimble County 2000 Series A due 08/01/30 Var%............................	17,222.57	33,912.71	190,871.84	391,280.96	190,871.84	391,280.96
Jefferson County 2001 Series A due 09/01/26 Var%.........................	920.59	3,600.95	19,062.75	47,135.13	19,062.75	47,135.13
Jefferson County 2001 Series A due 09/01/27 Var%..........................	5,868.50	23,886.98	166,740.43	188,907.55	166,740.43	188,907.55
Jefferson County 2001 Series B due 11/01/27 Var%.........................	13,376.72	23,541.10	272,311.80	356,505.13	272,311.80	356,505.13
Trimble County 2001 Series A due 09/01/26 Var%............................	7,707.53	12,845.88	98,532.88	165,015.07	98,532.88	165,015.07
Trimble County 2001 Series A due 10/01/32 Var%............................	3,538.67	16,258.48	112,134.76	294,966.89	112,134.76	294,966.89
Trimble County 2001 Series B due 11/01/27 Var%............................	13,568.50	23,541.10	270,890.13	356,549.22	270,890.13	356,549.22
Louisville Metro 2003 Series A due 10/01/33 1.900%.......................	202,666.67	-	2,350,933.23	-	2,350,933.23	-
Louisville Metro 2005 Series A due 02/01/35 5.750%.......................	191,666.66	191,666.67	2,299,999.98	2,299,999.91	2,299,999.98	2,299,999.91
Louisville Metro 2007 Series A due 06/01/33 5.625%.......................	145,312.49	145,312.50	1,743,749.88	1,743,749.95	1,743,749.88	1,743,749.95
Louisville Metro 2007 Series B due 06/01/33 1.900%........................	55,733.34	-	648,364.50	-	648,364.50	-
Trimble County 2007 Series A due 06/01/33 4.600%.........................	230,000.00	230,000.00	2,760,000.00	2,760,000.00	2,760,000.00	2,760,000.00
Interest Rate Swaps..	695,186.64	703,043.52	7,772,721.91	7,698,340.31	7,772,721.91	7,698,340.31
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/15/15 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 11/15/40 5.125%..	1,217,187.50	1,217,187.50	14,606,250.00	1,825,781.25	14,606,250.00	1,825,781.25
Fidelia/PPL...	-	-	-	23,320,575.03	-	23,320,575.03
Revolving Credit Agreement...	-	318,393.33	185,005.01	594,678.34	185,005.01	594,678.34
Total..	3,156,393.86	3,393,711.56	38,809,735.79	43,895,047.17	38,809,735.79	43,895,047.17
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense...	159,869.70	170,036.09	2,098,126.45	453,375.01	2,098,126.45	453,375.01
Amortization of Loss on Reacquired Debt..	102,314.11	101,002.98	1,213,346.78	1,211,250.73	1,213,346.78	1,211,250.73
Total..	262,183.81	271,039.07	3,311,473.23	1,664,625.74	3,311,473.23	1,664,625.74
Other Interest Charges						
Customers' Deposits...	115,726.44	112,067.13	1,383,634.99	1,388,906.46	1,383,634.99	1,388,906.46
Other Tax Deficiencies..	-	-	14,000.00	(17,500.00)	14,000.00	(17,500.00)
Interest on DSM Cost Recovery..	1,214.55	1,263.02	15,097.52	26,415.24	15,097.52	26,415.24
Interest on Debt to Associated Companies..	201.37	648.33	9,663.09	262,421.88	9,663.09	262,421.88
Other Interest Expense...	55,282.18	160,471.71	1,116,089.00	942,770.17	1,116,089.00	942,770.17
Total..	172,424.54	274,450.19	2,538,484.60	2,603,013.75	2,538,484.60	2,603,013.75
Total Interest..	$ 3,591,002.21	$ 3,939,200.82	$ 44,659,693.62	$ 48,162,686.66	$ 44,659,693.62	$ 48,162,686.66

January 26, 2012

Louisville Gas and Electric 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	$ 1,500,479.64	$ 431,812.94	$ 18,123,030.64	$ 12,935,303.74
Unemployment	69,875.67	37,049.46	198,143.29	202,916.50
FICA	701,548.07	1,039,353.30	7,810,191.79	7,462,190.44
Public Service Commission Fee	162,886.60	161,096.90	1,943,901.04	1,936,633.94
Federal Income	(7,561,185.42)	(6,078,915.85)	11,962,850.45	28,874,607.18
State Income	(968,373.77)	226,424.99	8,265,532.67	6,047,167.43
Miscellaneous	3,246.57	-	46,316.87	34,579.20
Total Charged to Operating Expense	(6,091,522.64)	(4,183,178.26)	48,349,966.75	57,493,398.43
Taxes Charged to Other Accounts	5,621,851.74	(4,430,920.00)	7,173,388.04	5,858,666.85
Taxes Accrued on Intercompany Accounts	(22,955.47)	(399,203.84)	(1,882,993.86)	(3,039,101.12)
Total Taxes Charged	$ (492,626.37)	$ (9,013,302.10)	$ 53,640,360.93	$ 60,312,964.16

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	$ 11,354,131.66	$ 18,289,774.39	$ 17,645,481.23	$ 11,998,424.82
Unemployment	54,386.05	141,294.90	142,352.04	53,328.91
FICA	590,648.24	6,396,767.94	6,461,380.31	526,035.87
Federal Income	(3,741,320.05)	14,303,728.05	10,562,408.00	-
State Income	229,108.93	9,573,551.51	9,802,660.44	-
Kentucky Sales and Use Tax	1,088,857.95	4,804,648.54	5,221,713.26	671,793.23
Miscellaneous	22,339.97	130,595.60	117,668.84	35,266.73
Totals	$ 9,598,152.75	$ 53,640,360.93	$ 49,953,664.12	$ 13,284,849.56

January 26, 2012

Louisville Gas and Electric Company
Summary of Utility Plant
December 31, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant In Service**						
Common						
Common General Plant..	$ 159,884,459.36	$ 10,232,811.37	$ (13,029,370.28)	$ (30,818.06)	$ (2,827,376.97)	$ 157,057,082.39
Common Intangible Plant......................................	56,455,326.72	8,804,086.71	(4,368,250.60)	-	4,435,836.11	60,891,162.83
	216,339,786.08	19,036,898.08	(17,397,620.88)	(30,818.06)	1,608,459.14	217,948,245.22
Electric						
Electric Distribution...	927,289,038.50	43,796,656.74	(6,765,005.80)	192,486.41	37,224,137.35	964,513,175.85
Electric General Plant..	16,521,615.59	1,466,596.46	(2,140,531.84)	95,431.28	(578,504.10)	15,943,111.49
Electric Hydro Production.....................................	41,680,209.14	1,085,668.83	(229,943.87)	-	855,724.96	42,535,934.10
Electric Intangible Plant...	2,340.29	-	(100.00)	-	(100.00)	2,240.29
Electric Other Production......................................	229,401,033.01	5,823,654.94	(1,016,138.10)	38,429.14	4,845,945.98	234,246,978.99
Electric Steam Production......................................	1,930,347,044.43	205,718,450.78	(26,466,191.93)	4,911,561.46	184,163,820.31	2,114,510,864.74
Electric Transmission...	247,742,496.14	8,276,325.30	(1,599,170.73)	191,540.16	6,868,694.73	254,611,190.87
	3,392,983,777.10	266,167,353.05	(38,217,082.27)	5,429,448.45	233,379,719.23	3,626,363,496.33
Gas						
Gas Distribution...	549,799,120.70	47,985,396.30	(4,928,371.24)	95,174.66	43,152,199.72	592,951,320.42
Gas General Plant..	9,178,093.57	706,666.54	(1,494,730.21)	(185,857.43)	(973,921.10)	8,204,172.47
Gas Intangible Plant...	1,187.49	-	(800.00)	-	(800.00)	387.49
Gas Storage..	78,415,311.06	3,846,365.99	(1,705,113.67)	23,515.01	2,164,767.33	80,580,078.39
Gas Transmission...	16,661,869.68	958,868.98	(20,299.95)	3,941,518.65	4,880,087.68	21,541,957.36
	654,055,582.50	53,497,297.81	(8,149,315.07)	3,874,350.89	49,222,333.63	703,277,916.13
Total 101 Accounts………………………………	4,263,379,145.68	338,701,548.94	(63,764,018.22)	9,272,981.28	284,210,512.00	4,547,589,657.68
105 **Plant Held For Future Use**						
Electric						
Electric Distribution...	649,014.48	-	-	-	-	649,014.48
Electric Steam Production......................................	4,182,559.70	-	-	(4,182,559.70)	(4,182,559.70)	-
	4,831,574.18	-	-	(4,182,559.70)	(4,182,559.70)	649,014.48
Total 105001………………………………………	$ 4,831,574.18	$ -	$ -	$ (4,182,559.70)	$ (4,182,559.70)	$ 649,014.48

January 26, 2012

Louisville Gas and Electric Company
Summary of Utility Plant
December 31, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
106 **Completed Construction Not Classified**						
Common						
Common General Plant..	$ 597,158.63	$ 1,977,777.38	$ -	$ -	$ 1,977,777.38	$ 2,574,936.01
Common Intangible Plant.....................................	2,714,931.36	(474,047.10)	-	-	(474,047.10)	2,240,884.26
	3,312,089.99	1,503,730.28	-	-	1,503,730.28	4,815,820.27
Electric						
Electric Distribution..	11,544,733.90	11,667,501.64	-	-	11,667,501.64	23,212,235.54
Electric General Plant...	50,763.87	(44,000.65)	-	-	(44,000.65)	6,763.22
Electric Hydro Production.....................................	16,952.26	(495.90)	-	-	(495.90)	16,456.36
Electric Intangible Plant...	-	-	-	-	-	-
Electric Other Production......................................	1,767,208.21	1,768,751.53	-	-	1,768,751.53	3,535,959.74
Electric Steam Production......................................	15,929,229.77	25,312,444.81	-	-	25,312,444.81	41,241,674.58
Electric Transmission..	35,045,472.82	2,663,310.20	-	-	2,663,310.20	37,708,783.02
	64,354,360.83	41,367,511.63	-	-	41,367,511.63	105,721,872.46
Gas						
Gas Distribution...	24,420,156.16	(5,554,171.68)	-	-	(5,554,171.68)	18,865,984.48
Gas General Plant..	126,992.17	136,081.61	-	-	136,081.61	263,073.78
Gas Intangible Plant...	-	-	-	-	-	-
Gas Storage..	951,426.06	(436,813.06)	-	-	(436,813.06)	514,613.00
Gas Transmission...	-	1,459,528.03	-	-	1,459,528.03	1,459,528.03
	25,498,574.39	(4,395,375.10)	-	-	(4,395,375.10)	21,103,199.29
Total 106 Accounts	93,165,025.21	38,475,866.81	-	-	38,475,866.81	131,640,892.02
117 **Gas Stored Underground-Noncurrent**						
Gas						
Gas Stored Nonrecoverable..................................	2,139,990.00	-	-	-	-	2,139,990.00
	2,139,990.00	-	-	-	-	2,139,990.00
Total 117001	2,139,990.00	-	-	-	-	2,139,990.00
121 **Nonutility Property**						
Common						
Non Utility Property...	75,239.56	-	-	-	-	75,239.56
	75,239.56	-	-	-	-	75,239.56
Total 121001	75,239.56	-	-	-	-	75,239.56
107 **Construction Work In Progress**						
Common..	21,243,879.89	(6,159,940.56)	-	-	(6,159,940.56)	15,083,939.33
Electric..	324,323,732.14	(171,612,904.07)	-	-	(171,612,904.07)	152,710,828.07
Gas..	39,756,306.91	7,725,303.03	-	-	7,725,303.03	47,481,609.94
	385,323,918.94	(170,047,541.60)	-	-	(170,047,541.60)	215,276,377.34
Total Plant (Non-CWIP).......................................	4,363,590,974.63	377,177,415.75	(63,764,018.22)	5,090,421.58	318,503,819.11	4,682,094,793.74
Total Plant + CWIP...	4,748,914,893.57	207,129,874.15	(63,764,018.22)	5,090,421.58	148,456,277.51	4,897,371,171.08
Total Plant + CWIP - Non Utility...........................	$ 4,748,839,654.01	$ 207,129,874.15	$ (63,764,018.22)	$ 5,090,421.58	$ 148,456,277.51	$ 4,897,295,931.52

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Louisville Gas and Electric 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										
Common General Plant	$ (77,263,235.10)	$ (12,884,072.63)	$ 13,029,370.28	$ 30,818.06	$ -	$ -	$ -	$ -	$ -	$ (77,087,119.39)
Common General Plant - ARO	(343.19)	(2,060.40)	-	-	-	-	-	-	-	(2,403.59)
Electric Distribution	(277,000,365.75)	(17,431,445.17)	6,765,005.80	(382.60)	-	-	-	-	-	(287,667,187.72)
Electric Distribution - ARO	(1,256.54)	(6,033.86)	-	-	-	-	-	-	-	(7,290.40)
Electric General Plant	(12,910,034.19)	(440,258.50)	2,140,531.84	(95,431.28)	-	-	-	-	-	(11,305,192.13)
Electric Hydro Production	(9,718,276.66)	(563,664.43)	229,943.87	-	-	-	-	-	-	(10,051,997.22)
Electric Hydro Production - ARO	(364.10)	(1,748.52)	-	-	-	-	-	-	-	(2,112.62)
Electric Other Production	(60,282,055.17)	(8,200,823.60)	1,016,138.10	-	-	-	-	-	-	(67,466,740.67)
Electric Other Production - ARO	(192.68)	(1,110.14)	-	-	-	-	-	-	-	(1,302.82)
Electric Steam Production	(1,029,518,070.37)	(56,830,079.38)	25,733,986.89	-	-	-	-	-	-	(1,060,614,162.86)
Electric Steam Production - ARO	(204,061.94)	(2,050,928.42)	732,205.04	120,737.40	-	-	-	-	-	(1,402,047.92)
Electric Transmission	(119,192,606.75)	(4,396,251.42)	1,599,170.73	382.60	-	-	-	-	-	(121,989,304.84)
Electric Transmission - ARO	(41.40)	(861.88)	-	-	-	-	-	-	-	(903.28)
Gas Distribution	(125,049,477.23)	(11,625,947.76)	4,853,331.97	(13,332.40)	-	-	-	-	-	(131,835,425.42)
Gas Distribution - ARO	(49,734.93)	(374,096.39)	75,039.27	2,554.54	-	-	-	-	-	(346,237.51)
Gas General Plant	(6,299,629.20)	(326,638.20)	1,494,730.21	87,301.32	-	-	-	-	-	(5,044,235.87)
Gas Storage	(31,288,281.49)	(1,083,855.81)	1,309,708.21	(9,355.70)	-	-	-	-	-	(31,071,784.79)
Gas Storage - ARO	(39,466.10)	(613,490.60)	395,405.46	-	-	-	-	-	-	(257,551.24)
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(9,448,605.32)	(58,051.01)	20,299.95	-	-	-	-	-	-	(9,486,356.38)
Gas Transmission - ARO	-	(35,270.86)	-	-	-	-	-	-	-	(35,270.86)
Non Utility Property	(63,360.36)	-	-	-	-	-	-	-	-	(63,360.36)
	(1,758,329,458.47)	(116,926,688.98)	59,394,867.62	123,291.94	-	-	-	-	-	(1,815,737,987.89)
Cost Of Removal										
Common General Plant	(688,372.47)	(282,352.73)	-	-	-	-	332,962.76	-	-	(637,762.44)
Electric Distribution	(146,715,298.78)	(6,906,243.62)	-	(55.48)	-	-	4,671,834.71	-	-	(148,949,763.17)
Electric General Plant	3,866.64	-	-	-	-	-	-	-	-	3,866.64
Electric Hydro Production	736,907.70	(42,804.01)	-	-	-	-	38,351.42	-	-	732,455.11
Electric Other Production	(2,505,175.99)	(351,752.52)	-	-	-	-	320,969.80	-	-	(2,535,958.71)
Electric Steam Production	(94,783,295.15)	(17,004,689.96)	-	(653,829.16)	-	-	4,150,422.77	-	-	(108,291,391.50)
Electric Transmission	(24,538,454.78)	(1,414,732.76)	-	(18,417.50)	-	-	211,880.17	-	-	(25,759,724.87)
Gas Distribution	(60,212,131.14)	(3,290,875.18)	-	-	-	-	1,501,606.49	-	-	(62,001,399.83)
Gas General Plant	(0.02)	-	-	-	-	-	-	-	-	(0.02)
Gas Storage	(170,437.90)	(141,062.94)	-	(258,005.34)	-	-	831,976.72	-	-	262,470.54
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(3,016,813.95)	(14,363.81)	-	-	-	-	46,319.99	-	-	(2,984,857.77)
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	$ (331,889,205.84)	$ (29,448,877.53)	$ -	$ (930,307.48)	$ -	$ -	$ 12,106,324.83	$ -	$ -	$ (350,162,066.02)

January 26, 2012

Louisville Gas and Electric 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
Salvage										
Common General Plant	$ 278,074.55	$ 383.28	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 278,457.83
Electric Distribution	17,535,024.98	1,400,330.13	-	-	-	-	-	(404,132.63)	-	18,531,222.48
Electric General Plant	138,281.25	2,307.97	-	-	-	-	-	-	-	140,589.22
Electric Hydro Production	376,638.17	-	-	-	-	-	-	-	-	376,638.17
Electric Other Production	(18,998.67)	-	-	-	-	-	-	-	-	(18,998.67)
Electric Steam Production	22,028,570.14	2,026,744.89	-	-	-	-	-	(34,636.38)	-	24,020,678.65
Electric Transmission	6,247,368.67	262,392.97	-	1,254.13	-	-	-	-	-	6,511,015.77
Gas Distribution	3,594,440.75	200,136.01	-	-	-	-	-	(3,121.65)	-	3,791,455.11
Gas General Plant	225,788.37	2,371.24	-	-	-	-	-	-	-	228,159.61
Gas Storage	269,933.04	17,219.17	-	-	-	-	-	-	-	287,152.21
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	217,923.11	5,386.42	-	-	-	-	-	-	-	223,309.53
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	50,893,044.36	3,917,272.08	-	1,254.13	-	-	-	(441,890.66)	-	54,369,679.91
Total Reserves										
Common	(77,737,236.57)	(13,168,102.48)	13,029,370.28	30,818.06	-	-	332,962.76	-	-	(77,512,187.95)
Electric	(1,730,321,891.37)	(111,951,652.23)	38,216,982.27	(645,741.89)	-	-	9,393,458.87	(438,769.01)	-	(1,795,747,613.36)
Gas	(231,266,492.01)	(17,338,539.72)	8,148,515.07	(190,837.58)	-	-	2,379,903.20	(3,121.65)	-	(238,270,572.69)
	(2,039,325,619.95)	(142,458,294.43)	59,394,867.62	(805,761.41)	-	-	12,106,324.83	(441,890.66)	-	(2,111,530,374.00)
Retirement Work In Progress										
Common	342,947.00	-	-	162,020.85	-	(332,962.76)	67,831.34	(91,219.00)	1,144.92	149,762.35
Electric	9,603,653.21	-	-	(71,982.35)	(1,142,636.19)	(7,812,053.67)	12,448,616.33	(543,373.97)	(557,508.33)	11,924,715.03
Gas	2,523,160.64	-	-	(30,745.64)	(1,053,809.06)	(1,322,972.49)	1,484,772.89	(7,015.24)	(2,703.32)	1,590,687.78
	12,469,760.85	-	-	59,292.86	(2,196,445.25)	(9,467,988.92)	14,001,220.56	(641,608.21)	(559,066.73)	13,665,165.16
YTD ACTIVITY	(2,026,855,859.10)	(142,458,294.43)	59,394,867.62	(746,468.55)	(2,196,445.25)	(9,467,988.92)	26,107,545.39	(1,083,498.87)	(559,066.73)	(2,097,865,208.84)
Amortization										
Common	(16,306,390.60)	(8,133,464.03)	4,368,250.60	-	-	-	-	-	-	(20,071,604.03)
Electric	(100.00)	-	100.00	-	-	-	-	-	-	-
Gas	(800.00)	-	800.00	-	-	-	-	-	-	-
AMORTIZATION TOTAL	(16,307,290.60)	(8,133,464.03)	4,369,150.60	-	-	-	-	-	-	(20,071,604.03)
Depreciation & Amortization Total	$ (2,043,163,149.70)	$ (150,591,758.46)	$ 63,764,018.22	$ (746,468.55)	$ (2,196,445.25)	$ (9,467,988.92)	$ 26,107,545.39	$ (1,083,498.87)	$ (559,066.73)	$ (2,117,936,812.87)
Depr & Amort - Nonutility for Balance Sheet										(2,117,873,452.51)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)	$ 2,705,739,864.67									$ 2,779,422,479.01

January 26, 2012

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
December 31, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues.......................................	$ 84,801,954.82	$ -	$ 84,801,954.82
Gas Operating Revenues...	41,094,658.46	-	41,094,658.46
Total Operating Revenues..	125,896,613.28	-	125,896,613.28
Fuel for Electric Generation..	32,429,492.43	-	32,429,492.43
Power Purchased...	6,940,294.11	-	6,940,294.11
Gas Supply Expenses..	20,934,175.22	-	20,934,175.22
Other Operation Expenses...	19,759,510.34	-	19,759,510.34
Maintenance..	8,933,526.92	-	8,933,526.92
Depreciation..	11,888,245.80	-	11,888,245.80
Amortization Expense...	699,391.68	-	699,391.68
Regulatory Credits...	(437,110.01)	-	(437,110.01)
Taxes			
Federal Income...	(7,561,185.42)	-	(7,561,185.42)
State Income..	(968,373.77)	-	(968,373.77)
Deferred Federal Income - Net.................................	13,652,179.03	8,169.01	13,660,348.04
Deferred State Income - Net.....................................	1,868,150.81	1,489.79	1,869,640.60
Property and Other...	2,438,036.55	-	2,438,036.55
Amortization of Investment Tax Credit.....................	(236,025.00)	-	(236,025.00)
Loss (Gain) from Disposition of Allowances...............	-	-	-
Accretion Expense..	231,701.50	-	231,701.50
Total Operating Expenses..	110,572,010.19	9,658.80	110,581,668.99
Net Operating Income...	15,324,603.09	(9,658.80)	15,314,944.29
Other Income Less Deductions.................................	419,450.96	-	419,450.96
Income Before Interest Charges................................	15,744,054.05	(9,658.80)	15,734,395.25
Interest on Long-Term Debt..	3,156,393.86	(25,017.63)	3,131,376.23
Amortization of Debt Expense - Net...........................	262,183.81	-	262,183.81
Other Interest Expenses...	172,424.54	-	172,424.54
Total Interest Charges..	3,591,002.21	(25,017.63)	3,565,984.58
Net Income..	$ 12,153,051.84	$ 15,358.83	$ 12,168,410.67

January 26, 2012

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
December 31, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues..	$ 1,059,750,303.49	$ -	$ 1,059,750,303.49
Gas Operating Revenues..	304,574,421.82	-	304,574,421.82
Total Operating Revenues...	1,364,324,725.31	-	1,364,324,725.31
Fuel for Electric Generation...	360,968,393.36	-	360,968,393.36
Power Purchased..	74,894,547.12	-	74,894,547.12
Gas Supply Expenses...	161,235,625.70	-	161,235,625.70
Other Operation Expenses...	236,277,354.89	27,884.66	236,305,239.55
Maintenance...	116,359,068.55	-	116,359,068.55
Depreciation...	141,998,214.92	-	141,998,214.92
Amortization Expense..	8,133,464.03	-	8,133,464.03
Regulatory Credits...	(5,730,085.69)	-	(5,730,085.69)
Taxes			
Federal Income..	11,962,850.45	-	11,962,850.45
State Income...	8,265,532.67	-	8,265,532.67
Deferred Federal Income - Net..................................	52,223,724.36	89,595.56	52,313,319.92
Deferred State Income - Net.....................................	2,011,675.35	16,339.63	2,028,014.98
Property and Other..	28,121,583.64	-	28,121,583.64
Amortization of Investment Tax Credit....................	(2,805,732.00)	-	(2,805,732.00)
Loss (Gain) from Disposition of Allowances................	(2,577.94)	-	(2,577.94)
Accretion Expense...	2,644,484.62	-	2,644,484.62
Total Operating Expenses...	1,196,558,124.03	133,819.85	1,196,691,943.88
Net Operating Income..	167,766,601.28	(133,819.85)	167,632,781.43
Other Income Less Deductions.................................	1,079,397.77	-	1,079,397.77
Income Before Interest Charges................................	168,845,999.05	(133,819.85)	168,712,179.20
Interest on Long-Term Debt...	38,809,735.79	(300,211.56)	38,509,524.23
Amortization of Debt Expense - Net............................	3,311,473.23	-	3,311,473.23
Other Interest Expenses...	2,538,484.60	-	2,538,484.60
Total Interest Charges...	44,659,693.62	(300,211.56)	44,359,482.06
Net Income...	$ 124,186,305.43	$ 166,391.71	$ 124,352,697.14

January 26, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
December 31, 2011

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……………………………	$ 856,776,505.55	$ 813,953,056.34	$ (808,748,249.56)	$ (808,923,086.99)	$ 48,028,255.99	$ 5,029,969.35
Add:						
Net Income (Loss) for Period…………………………	12,153,051.84	14,040,195.62	15,358.83	23,804.55	12,168,410.67	14,064,000.17
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	-	-	-	-	-	-
Balance at End of Period…………………………………	$ 868,929,557.39	$ 827,993,251.96	$ (808,732,890.73)	$ (808,899,282.44)	$ 60,196,666.66	$ 19,093,969.52

January 26, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
December 31, 2011

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period................................	$ 827,993,251.96	$ 755,278,866.24	$ (808,899,282.44)	$ -	$ 19,093,969.52	$ 755,278,866.24
Add:						
Net Income (Loss) for Period.............................	124,186,305.43	127,714,385.72	166,391.71	47,609.08	124,352,697.14	127,761,994.80
Deduct:						
Adjustment to Retained Earnings.........................	-	-	-	808,946,891.52	-	808,946,891.52
Common Dividends						
Common Stock Without Par Value..................	83,250,000.00	55,000,000.00	-	-	83,250,000.00	55,000,000.00
Balance at End of Period.......................................	$ 868,929,557.39	$ 827,993,251.96	$ (808,732,890.73)	$ (808,899,282.44)	$ 60,196,666.66	$ 19,093,969.52

January 26, 2012

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
December 31, 2011

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……	$ 827,993,251.96	$ 755,278,866.24	$ (808,899,282.44)	$ -	$ 19,093,969.52	$ 755,278,866.24
Add:						
Net Income (Loss) for Period……	124,186,305.43	127,714,385.72	166,391.71	47,609.08	124,352,697.14	127,761,994.80
Deduct:						
Adjustment to Retained Earnings……	-	-	-	808,946,891.52	-	808,946,891.52
Common Dividends						
Common Stock Without Par Value……	83,250,000.00	55,000,000.00	-	-	83,250,000.00	55,000,000.00
Balance at End of Period……	$ 868,929,557.39	$ 827,993,251.96	$ (808,732,890.73)	$ (808,899,282.44)	$ 60,196,666.66	$ 19,093,969.52

January 26, 2012

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of December 31, 2011

Assets	Without Purchase Accounting	Purchase Accounting	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 4,897,295,931.52	$ -	$ 4,897,295,931.52
Less: Reserves for Depreciation and Amortization....	2,117,873,452.51	-	2,117,873,452.51
Total..	2,779,422,479.01	-	2,779,422,479.01
Investments			
Ohio Valley Electric Corporation.............................	594,286.00	-	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	-	11,879.20
Special Funds...	28,846,730.20	-	28,846,730.20
Total..	29,452,895.40	-	29,452,895.40
Current and Accrued Assets			
Cash..	24,920,484.53	-	24,920,484.53
Special Deposits...	12,277.00	-	12,277.00
Temporary Cash Investments...................................	33,063.99	-	33,063.99
Accounts Receivable - Less Reserve.........................	137,419,594.66	-	137,419,594.66
Accounts Receivable from Associated Companies....	10,916,898.01	-	10,916,898.01
Materials and Supplies - At Average Cost			
Fuel..	52,502,546.26	-	52,502,546.26
Plant Materials and Operating Supplies..................	30,625,941.68	-	30,625,941.68
Stores Expense...	5,596,505.54	-	5,596,505.54
Gas Stored Underground.......................................	53,287,604.59	-	53,287,604.59
Emission Allowances...	2,511.67	-	2,511.67
Prepayments..	5,472,353.44	-	5,472,353.44
Miscellaneous Current and Accrued Assets..............	-	-	-
Total..	320,789,781.37	-	320,789,781.37
Deferred Debits and Other			
Unamortized Debt Expense......................................	13,326,195.59	(3,481,180.65)	9,845,014.94
Unamortized Loss on Bonds....................................	20,963,862.78	-	20,963,862.78
Accumulated Deferred Income Taxes........................	23,826,072.01	67,074,595.36	90,900,667.37
Deferred Regulatory Assets.....................................	397,110,901.24	9,013,134.12	406,124,035.36
Other Deferred Debits..	1,480,708.22	160,669,842.02	162,150,550.24
Goodwill..	-	389,157,351.59	389,157,351.59
Total..	456,707,739.84	622,433,742.44	1,079,141,482.28
Total Assets..	$ 3,586,372,895.62	$ 622,433,742.44	$ 4,208,806,638.06

January 26, 2012

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of December 31, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting	Total
Proprietary Capital			
Common Stock...	$ 425,170,424.09	$ -	$ 425,170,424.09
Less: Common Stock Expense......................................	835,888.64	-	835,888.64
Paid-In Capital...	83,581,499.00	1,194,085,869.02	1,277,667,368.02
Other Comprehensive Income.......................................	-	-	-
Retained Earnings...	868,929,557.39	(808,732,890.73)	60,196,666.66
Total Proprietary Capital...	1,376,845,591.84	385,352,978.29	1,762,198,570.13
Pollution Control Bonds - Net of Reacquired Bonds.....	574,304,000.00	6,226,470.18	580,530,470.18
First Mortgage Bonds..	531,331,542.44	-	531,331,542.44
LT Notes Payable to Associated Companies................	-	-	-
Total Long-Term Debt...	1,105,635,542.44	6,226,470.18	1,111,862,012.62
Total Capitalization...	2,482,481,134.28	391,579,448.47	2,874,060,582.75
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies.................	-	-	-
Accounts Payable...	97,848,807.56	-	97,848,807.56
Accounts Payable to Associated Companies................	25,528,425.55	-	25,528,425.55
Customer Deposits...	22,361,041.85	-	22,361,041.85
Taxes Accrued...	13,284,849.56	-	13,284,849.56
Interest Accrued...	5,825,755.42	-	5,825,755.42
Miscellaneous Current and Accrued Liabilities............	22,176,210.30	-	22,176,210.30
Total..	187,025,090.24	-	187,025,090.24
Deferred Credits and Other			
Accumulated Deferred Income Taxes...........................	499,655,847.56	64,652,498.48	564,308,346.04
Investment Tax Credit...	42,718,844.13	-	42,718,844.13
Regulatory Liabilities...	58,617,596.40	160,669,842.02	219,287,438.42
Customer Advances for Construction...........................	7,307,168.56	-	7,307,168.56
Asset Retirement Obligations..	58,606,350.25	-	58,606,350.25
Other Deferred Credits..	5,120,367.14	5,531,953.47	10,652,320.61
Miscellaneous Long-Term Liabilities...........................	60,707,001.86	-	60,707,001.86
Misc Long-Term Liab Due to Assoc Cos......................	-	-	-
Accum Provision for Postretirement Benefits................	184,133,495.20	-	184,133,495.20
Total..	916,866,671.10	230,854,293.97	1,147,720,965.07
Total Liabilities and Stockholders' Equity..........................	$ 3,586,372,895.62	$ 622,433,742.44	$ 4,208,806,638.06

January 26, 2012

LOUISVILLE GAS AND ELECTRIC COMPANY

Financial Reports

November 30, 2011

Index
Financial and Operating Reports

Louisville Gas and Electric 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.

Louisville Gas and Electric Company
Comparative Statement of Income
November 30, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 79,790,596.68	$ 75,474,375.66	$ 4,316,221.02	5.72
Gas Operating Revenues...	26,654,047.95	28,775,894.40	(2,121,846.45)	(7.37)
Total Operating Revenues...	106,444,644.63	104,250,270.06	2,194,374.57	2.10
Fuel for Electric Generation...	28,153,852.37	28,583,040.32	(429,187.95)	(1.50)
Power Purchased..	5,064,747.78	4,597,979.19	466,768.59	10.15
Gas Supply Expenses...	13,753,574.24	15,846,801.16	(2,093,226.92)	(13.21)
Other Operation Expenses..	19,493,999.54	21,037,578.69	(1,543,579.15)	(7.34)
Maintenance..	10,820,356.27	9,815,100.39	1,005,255.88	10.24
Depreciation..	11,890,425.36	10,887,294.43	1,003,130.93	9.21
Amortization Expense...	717,415.76	631,375.25	86,040.51	13.63
Regulatory Credits..	(413,283.37)	(320,640.19)	(92,643.18)	(28.89)
Taxes				
Federal Income..	3,545,983.02	2,710,579.67	835,403.35	30.82
State Income...	661,075.08	494,330.64	166,744.44	33.73
Deferred Federal Income - Net.................................	(18,861.57)	-	(18,861.57)	(100.00)
Deferred State Income - Net......................................	279,395.94	-	279,395.94	100.00
Property and Other..	2,267,705.13	708,449.42	1,559,255.71	220.09
Investment Tax Credit...	-	-	-	-
Amortization of Investment Tax Credit.....................	(236,034.00)	(208,481.00)	(27,553.00)	(13.22)
Loss (Gain) from Disposition of Allowances...............	-	-	-	-
Accretion Expense..	230,714.66	216,795.73	13,918.93	6.42
Total Operating Expenses...	96,211,066.21	95,000,203.70	1,210,862.51	1.27
Net Operating Income..	10,233,578.42	9,250,066.36	983,512.06	10.63
Other Income Less Deductions.................................	127,698.96	(236,249.84)	363,948.80	154.05
Income Before Interest Charges................................	10,361,277.38	9,013,816.52	1,347,460.86	14.95
Interest on Long-Term Debt...	2,990,614.58	3,615,035.62	(624,421.04)	(17.27)
Amortization of Debt Expense - Net............................	260,610.04	229,016.05	31,593.99	13.80
Other Interest Expenses..	195,730.28	163,600.03	32,130.25	19.64
Total Interest Charges...	3,446,954.90	4,007,651.70	(560,696.80)	(13.99)
Net Income..	$ 6,914,322.48	$ 5,006,164.82	$ 1,908,157.66	38.12

December 22, 2011

Louisville Gas and Electric Company
Comparative Statement of Income
November 30, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 974,948,348.67	$ 921,860,119.63	$ 53,088,229.04	5.76
Gas Operating Revenues...	263,479,763.36	245,653,124.21	17,826,639.15	7.26
Total Operating Revenues...	1,238,428,112.03	1,167,513,243.84	70,914,868.19	6.07
Fuel for Electric Generation...	328,538,900.93	334,061,246.26	(5,522,345.33)	(1.65)
Power Purchased...	67,954,253.01	49,589,290.10	18,364,962.91	37.03
Gas Supply Expenses..	140,301,450.48	131,002,537.35	9,298,913.13	7.10
Other Operation Expenses..	216,517,844.55	208,101,453.32	8,416,391.23	4.04
Maintenance..	107,425,541.63	96,740,064.18	10,685,477.45	11.05
Depreciation..	130,109,969.12	120,215,941.59	9,894,027.53	8.23
Amortization Expense...	7,434,072.35	7,092,877.08	341,195.27	4.81
Regulatory Credits..	(5,292,975.68)	(3,860,387.93)	(1,432,587.75)	(37.11)
Taxes				
Federal Income..	19,524,035.87	34,953,523.03	(15,429,487.16)	(44.14)
State Income...	9,233,906.44	5,820,742.44	3,413,164.00	58.64
Deferred Federal Income - Net.................................	38,571,545.33	14,485,407.74	24,086,137.59	166.28
Deferred State Income - Net......................................	143,524.54	1,367,098.28	(1,223,573.74)	(89.50)
Property and Other..	25,683,547.09	20,902,311.22	4,781,235.87	22.87
Investment Tax Credit...	-	-	-	-
Amortization of Investment Tax Credit.....................	(2,569,707.00)	(2,293,293.00)	(276,414.00)	(12.05)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	2,412,783.12	3,066,378.53	(653,595.41)	(21.31)
Total Operating Expenses...	1,085,986,113.84	1,021,210,730.05	64,775,383.79	6.34
Net Operating Income..	152,441,998.19	146,302,513.79	6,139,484.40	4.20
Other Income Less Deductions.................................	659,946.81	11,595,162.15	(10,935,215.34)	(94.31)
Income Before Interest Charges................................	153,101,945.00	157,897,675.94	(4,795,730.94)	(3.04)
Interest on Long-Term Debt...	35,653,341.93	40,501,335.61	(4,847,993.68)	(11.97)
Amortization of Debt Expense - Net............................	3,049,289.42	1,393,586.67	1,655,702.75	118.81
Other Interest Expenses..	2,366,060.06	2,328,563.56	37,496.50	1.61
Total Interest Charges...	41,068,691.41	44,223,485.84	(3,154,794.43)	(7.13)
Net Income..	$ 112,033,253.59	$ 113,674,190.10	$ (1,640,936.51)	(1.44)

December 22, 2011

Louisville Gas and Electric 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..	$ 1,068,699,796.01	$ 1,002,042,244.51	$ 66,657,551.50	6.65
Gas Operating Revenues...	320,773,995.03	292,407,467.81	28,366,527.22	9.70
Total Operating Revenues...	1,389,473,791.04	1,294,449,712.32	95,024,078.72	7.34
Fuel for Electric Generation...	363,033,981.01	360,791,405.72	2,242,575.29	0.62
Power Purchased..	72,744,681.60	55,554,169.98	17,190,511.62	30.94
Gas Supply Expenses..	178,302,521.18	164,398,359.32	13,904,161.86	8.46
Other Operation Expenses..	235,229,395.80	225,293,421.35	9,935,974.45	4.41
Maintenance..	122,386,582.53	107,985,447.34	14,401,135.19	13.34
Depreciation..	141,104,030.80	130,940,039.89	10,163,990.91	7.76
Amortization Expense...	8,068,184.17	7,797,046.73	271,137.44	3.48
Regulatory Credits..	(5,702,319.20)	(4,038,772.03)	(1,663,547.17)	(41.19)
Taxes				
Federal Income..	13,445,120.02	53,181,341.99	(39,736,221.97)	(74.72)
State Income...	9,460,331.43	7,074,381.80	2,385,949.63	33.73
Deferred Federal Income - Net.................................	51,753,142.59	(937,008.36)	52,690,150.95	5,623.23
Deferred State Income - Net......................................	1,146,450.70	773,200.84	373,249.86	48.27
Property and Other..	27,352,859.69	22,135,646.96	5,217,212.73	23.57
Investment Tax Credit...	-	703,437.35	(703,437.35)	(100.00)
Amortization of Investment Tax Credit.....................	(2,778,188.00)	(2,535,334.48)	(242,853.52)	(9.58)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	2,630,510.22	3,230,122.90	(599,612.68)	(18.56)
Total Operating Expenses...	1,218,174,706.60	1,132,312,447.16	85,862,259.44	7.58
Net Operating Income..	171,299,084.44	162,137,265.16	9,161,819.28	5.65
Other Income Less Deductions.................................	(217,743.00)	13,769,762.51	(13,987,505.51)	(101.58)
Income Before Interest Charges................................	171,081,341.44	175,907,027.67	(4,825,686.23)	(2.74)
Interest on Long-Term Debt...	39,047,053.49	44,126,446.12	(5,079,392.63)	(11.51)
Amortization of Debt Expense - Net............................	3,320,328.49	1,509,876.17	1,810,452.32	119.91
Other Interest Expenses..	2,640,510.25	2,757,099.99	(116,589.74)	(4.23)
Total Interest Charges...	45,007,892.23	48,393,422.28	(3,385,530.05)	(7.00)
Net Income..	$ 126,073,449.21	$ 127,513,605.39	$ (1,440,156.18)	(1.13)

December 22, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings
November 30, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period..	$ 877,862,183.07	$ 808,946,891.52	$ 827,993,251.96	$ 755,278,866.24	$ 813,953,056.34	$ 741,439,450.95
Add:						
Net Income for Period..	6,914,322.48	5,006,164.82	112,033,253.59	113,674,190.10	126,073,449.21	127,513,605.39
Deduct:						
Common Dividends						
Common Stock Without Par Value.....................	28,000,000.00	-	83,250,000.00	55,000,000.00	83,250,000.00	55,000,000.00
Balance at End of Period...	$ 856,776,505.55	$ 813,953,056.34	$ 856,776,505.55	$ 813,953,056.34	$ 856,776,505.55	$ 813,953,056.34

December 22, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of November 30, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 4,872,997,987.35	$ 4,725,820,363.00
Less: Reserves for Depreciation and Amortization....	2,126,828,778.97	2,038,048,102.91
Total...	2,746,169,208.38	2,687,772,260.09
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve............................	11,879.20	11,879.20
Special Funds..	28,514,787.39	21,159,746.63
Total...	29,120,952.59	21,765,911.83
Current and Accrued Assets		
Cash..	34,195,977.48	8,943,622.67
Special Deposits..	-	694,907.86
Temporary Cash Investments....................................	29,029,898.75	257.35
Accounts Receivable - Less Reserve.........................	114,669,412.44	120,611,707.66
Accounts Receivable from Associated Companies....	11,548,437.29	12,503,081.78
Materials and Supplies - At Average Cost................		
Fuel...	55,707,094.47	72,766,804.02
Plant Materials and Operating Supplies..................	30,482,076.24	29,408,708.50
Stores Expense...	5,550,219.41	4,916,530.71
Gas Stored Underground..	62,658,874.27	69,206,931.68
Emission Allowances..	26,604.68	2,872.24
Prepayments..	4,982,269.92	12,611,917.95
Miscellaneous Current and Accrued Assets..............	-	455,865.92
Total...	348,850,864.95	332,123,208.34
Deferred Debits and Other		
Unamortized Debt Expense.......................................	13,447,248.44	11,959,147.13
Unamortized Loss on Bonds......................................	20,823,617.00	22,035,652.40
Accumulated Deferred Income Taxes.......................	26,355,404.03	49,259,820.29
Deferred Regulatory Assets.......................................	379,199,955.06	367,782,479.06
Other Deferred Debits...	1,649,265.49	1,205,148.42
Total...	441,475,490.02	452,242,247.30
Total Assets...	$ 3,565,616,515.94	$ 3,493,903,627.56

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense..................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income..................................	-	-
Retained Earnings...	856,776,505.55	813,953,056.34
Total Proprietary Capital..	1,364,692,540.00	1,321,869,090.79
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds..	531,308,220.78	531,028,360.84
LT Notes Payable to Associated Companies............	-	-
Total Long-Term Debt...	1,105,612,220.78	942,132,360.84
Total Capitalization..	2,470,304,760.78	2,264,001,451.63
Current and Accrued Liabilities		
Notes Payable...	-	163,000,000.00
Accounts Payable..	81,283,596.90	93,382,514.42
Accounts Payable to Associated Companies............	16,784,036.42	20,131,634.53
Customer Deposits..	22,388,530.85	23,813,630.54
Taxes Accrued..	29,529,563.22	12,466,240.58
Interest Accrued..	5,951,860.54	2,515,610.98
Dividends Declared...	28,000,000.00	-
Miscellaneous Current and Accrued Liabilities.........	19,807,279.09	18,067,321.29
Total...	203,744,867.02	333,376,952.34
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	487,425,528.06	454,586,900.11
Investment Tax Credit..	42,954,869.13	45,733,057.13
Regulatory Liabilities..	60,622,974.76	51,586,279.37
Customer Advances for Construction.......................	7,247,002.77	8,466,567.41
Asset Retirement Obligations...................................	56,022,754.36	52,433,061.81
Other Deferred Credits..	35,534,880.32	35,528,957.25
Miscellaneous Long-Term Liabilities.......................	57,497,148.14	45,581,269.32
Accum Provision for Postretirement Benefits...........	144,261,730.60	202,609,131.19
Total...	891,566,888.14	896,525,223.59
Total Liabilities and Stockholders' Equity.....................	$ 3,565,616,515.94	$ 3,493,903,627.56

December 22, 2011

Louisville Gas and Electric 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...	75,000,000	21,294,223	$ 425,170,424.09	
Less: Common Stock Expense...			835,888.64	
Paid-In Capital...			83,581,499.00	
Other Comprehensive Income...			-	
Retained Earnings...			856,776,505.55	
Total Proprietary Capital...			1,364,692,540.00	55.24
Long-Term Debt				
Pollution Control Bonds..				
Jefferson County 2000 Series A due 05/01/27 5.375%.................			25,000,000.00	
Trimble County 2000 Series A due 08/01/30 Var%......................			83,335,000.00	
Jefferson County 2001 Series A due 09/01/26 Var%...................			22,500,000.00	
Jefferson County 2001 Series A due 09/01/27 Var%....................			10,104,000.00	
Jefferson County 2001 Series B due 11/01/27 Var%...................			35,000,000.00	
Trimble County 2001 Series A due 09/01/26 Var%......................			27,500,000.00	
Trimble County 2001 Series A due 10/01/32 Var%......................			41,665,000.00	
Trimble County 2001 Series B due 11/01/27 Var%......................			35,000,000.00	
Louisville Metro 2003 Series A due 10/01/33 1.900%..................			128,000,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%..................			40,000,000.00	
Louisville Metro 2007 Series A due 06/01/33 5.625%..................			31,000,000.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%..................			35,200,000.00	
Trimble County 2007 Series A due 06/01/33 4.600%...................			60,000,000.00	
Total Pollution Control Bonds...			574,304,000.00	23.25
First Mortgage Bonds..				
First Mortgage Bond Due 11/15/15 1.625%..................................			250,000,000.00	
First Mortgage Bond Due 11/15/40 5.125%..................................			285,000,000.00	
Total First Mortgage Bonds...			535,000,000.00	21.66
Less: First Mortgage Bonds Debt Discount.....................................				
First Mortgage Bond Due 11/15/15 1.625%..................................			(698,645.86)	
First Mortgage Bond Due 11/15/40 5.125%..................................			(2,993,133.36)	
			(3,691,779.22)	-0.15
Total First Mortgage Bonds - Net of Debt Discount.........................			531,308,220.78	21.51
Total Capitalization..			$ 2,470,304,760.78	100.00

December 22, 2011

Louisville Gas and Electric Company
Summary Trial Balance
November 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 4,872,997,987.35	$ 4,872,997,987.35
Reserves for Depreciation and Amortization		(2,126,828,778.97)
Depreciation of Plant		
Electric	(1,776,095,752.10)	
Gas	(240,129,749.75)	
Common	(88,523,715.75)	
Amortization of Plant		
Common	(22,078,661.37)	
Gas	(800.00)	
Electric	(100.00)	
Investments		29,120,952.59
Special Funds	28,514,787.39	
Ohio Valley Electric Corporation	594,286.00	
Nonutility Property	11,879.20	
Cash	34,195,977.48	34,195,977.48
Temporary Cash Investments	29,029,898.75	29,029,898.75
Accounts Receivable - Less Reserve		114,669,412.44
Unbilled Revenues	55,746,364.47	
Customers - Active	48,641,969.71	
Wholesale Sales	3,552,924.71	
IMPA	2,550,072.03	
IMEA	2,472,130.59	
Sundry Accounts Receivable	1,197,373.88	
Transmission Sales	469,415.02	
Damage Claims	463,022.64	
Rents Receivable	236,163.61	
Electricity Swaps	166,354.87	
Mutual Aid	103,146.09	
Bechtel Liquidated Damages	5,700.00	
Other	719,220.23	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	5,488,290.65	
Accrual	(4,429,641.97)	
Reserve	(1,506,210.00)	
Recoveries	(1,059,824.56)	
A/R Miscellaneous	(147,059.53)	
Accounts Receivable from Associated Companies		11,548,437.29
LG&E - KU Energy Services/Kentucky Utilities	11,548,307.67	
PPL Energy Funding	129.62	
Fuel		55,707,094.47
Coal 1,172,916.25 Tons @ $46.96; MMBtu 26,562,379.10 @ 207.34¢	55,075,289.34	
Gas Pipeline 5,200 Mcf @ 17.56¢	91,299.33	
Fuel Oil 194,822.66 Gallons @ 277.43¢	540,505.80	
Plant Materials and Operating Supplies		30,482,076.24
Regular Materials and Supplies	29,598,880.32	
Limestone 100,912.60 Tons @ $8.75	883,195.92	
Stores Expense Undistributed	5,550,219.41	5,550,219.41
Gas Stored Underground - Current		62,658,874.27
Gas Stored Underground* 13,482,596 Mcf (14.73 psia) @ $4.65	62,658,874.27	
Emission Allowances	26,604.68	26,604.68

December 22, 2011

Louisville Gas and Electric Company
Summary Trial Balance
November 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Prepayments		$ 4,982,269.92
Insurance	1,890,428.16	
Taxes	1,140,206.26	
Rights of Way	226,666.71	
Risk Management and Workers Compensation	90,000.00	
Other	1,634,968.79	
Unamortized Debt Expense		13,447,248.44
Trimble County 2000 Series A due 08/01/30 Var%	722,537.65	
Jefferson County 2001 Series A due 09/01/26 Var%	146,375.64	
Jefferson County 2001 Series A due 09/01/27 Var%	321,181.78	
Jefferson County 2001 Series B due 11/01/27 Var%	175,007.73	
Trimble County 2001 Series A due 09/01/26 Var%	159,152.25	
Trimble County 2001 Series B due 11/01/27 Var%	175,036.44	
Trimble County 2002 Series A due 10/01/32 Var%	775,446.11	
Louisville Metro 2003 Series A Due 10/01/33 1.900%	434,189.06	
Louisville Metro 2007 Series B Due 06/01/33 1.900%	166,745.61	
Trimble County 2007 Series A due 06/01/33 4.600%	1,021,989.86	
First Mortgage Bond due 11/15/15 1.625%	2,063,320.34	
First Mortgage Bond due 11/15/40 5.125%	3,452,599.36	
Revolving Credit Agreement	3,833,666.61	
Unamortized Loss on Bonds	20,823,617.00	20,823,617.00
Accumulated Deferred Income Taxes		26,355,404.03
Federal		
Electric	19,457,852.79	
Gas	1,767,626.33	
State		
Electric	4,781,415.40	
Gas	348,509.51	
Regulatory Assets		379,199,955.06
Pension and Postretirement Benefits	213,180,670.00	
Interest Rate Swap Ineffectiveness	56,108,659.50	
2009 Winter Storm	37,993,272.37	
2008 Wind Storm	20,401,621.75	
Deferred Taxes - ASC 740		
Federal		
Electric	12,544,305.85	
State		
Electric	2,287,715.35	
Swap Termination	8,958,761.44	
Asset Retirement Obligations		
Electric	8,552,641.08	
Gas	1,085,757.80	
Common	8,441.99	
2011 Summer Storm	7,997,890.53	
Gas Supply Clause/PBR	4,254,592.83	
Fuel Adjustment Clause	2,938,000.00	
MISO Exit Fee	822,118.90	
Rate Case Expenses	815,976.39	
KCCS Funding	585,360.34	
EKPC FERC Transmission Costs	381,537.84	
CMRG Funding	162,600.00	
General Management Audit	120,031.10	
Other Deferred Debits	1,649,265.49	1,649,265.49
Total Assets	$ 3,565,616,515.94	$ 3,565,616,515.94

* Excludes:

	$	Mcf
Non-recoverable Base Gas	9,648,855.00	7,880,000
Recoverable Base Gas	2,139,990.00	2,930,000
	11,788,845.00	10,810,000

December 22, 2011

Louisville Gas and Electric Company
Summary Trial Balance
November 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 1,364,692,540.00
Common Stock	425,170,424.09	
Less: Common Stock Expense	835,888.64	
Paid-In Capital	83,581,499.00	
Retained Earnings	856,776,505.55	
Pollution Control Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,308,220.78	531,308,220.78
Accounts Payable		81,283,596.90
Regular	77,235,966.03	
Salaries and Wages Accrued	4,014,120.81	
Employee Withholdings Payable	33,510.06	
Accounts Payable to Associated Companies		16,784,036.42
LG&E - KU Energy Services/Kentucky Utilities	16,784,036.42	
Customers' Deposits	22,388,530.85	22,388,530.85
Taxes Accrued	29,529,563.22	29,529,563.22
Interest Accrued		5,951,860.54
Jefferson County 2000 Series A due 05/01/27 5.375%	111,979.17	
Trimble County 2000 Series A due 08/01/30 Var%	555.57	
Jefferson County 2001 Series A due 09/01/26 Var%	3,353.42	
Jefferson County 2001 Series A due 09/01/27 Var%	56.13	
Jefferson County 2001 Series B due 11/01/27 Var%	12,082.19	
Trimble County 2001 Series A due 09/01/26 Var%	2,712.33	
Trimble County 2001 Series A due 10/01/32 Var%	114.15	
Trimble County 2001 Series B due 11/01/27 Var%	13,198.63	
Louisville Metro 2003 Series A due 10/01/33 1.900%	405,333.33	
Louisville Metro 2005 Series A due 02/01/35 5.750%	760,277.78	
Louisville Metro 2007 Series A due 06/01/33 5.625%	871,875.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%	336,257.78	
Trimble County 2007 Series A due 06/01/33 4.600%	1,380,000.00	
Interest Rate Swaps	652,215.66	
First Mortgage Bond due 11/15/15 1.625%	180,555.56	
First Mortgage Bond due 11/15/40 5.125%	649,166.67	
Customers' Deposits	541,566.25	
Interest Accrued on Tax Liabilities	14,000.00	
Other	16,560.92	
Dividends Declared		28,000,000.00
Dividend Payable to LG&E and KU Energy LLC	28,000,000.00	
Miscellaneous Current and Accrued Liabilities		19,807,279.09
Vacation Pay Accrued	6,543,183.42	
ASC 815 Derivative Liability	4,263,262.23	
Customer Overpayments	4,008,400.47	
No-Notice Gas Payable	2,527,872.15	
Tax Collections Payable	864,719.75	
Postretirement Benefits - Current	624,694.04	
Unearned Revenue	458,483.13	
Home Energy Assistance	343,685.63	
Service Deposit Refund Payable	77,051.99	
Derivative Liabilities - Non-Hedging	(0.03)	
Other	95,926.31	

Louisville Gas and Electric Company
Summary Trial Balance
November 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Accumulated Deferred Income Taxes		$ 487,425,528.06
Federal		
Electric	343,634,266.79	
Gas	78,372,539.30	
State		
Electric	53,102,346.12	
Gas	12,316,375.85	
Investment Tax Credit		42,954,869.13
Advanced Coal Credit	23,189,878.00	
Job Development Credit		
Electric	19,197,511.98	
Gas	567,479.15	
Regulatory Liabilities		60,622,974.76
Deferred Taxes		
Federal		
Electric	28,183,235.06	
Gas	1,129,810.17	
State		
Electric	15,347,324.89	
Gas	2,483,161.13	
DSM Cost Recovery	4,848,724.58	
Gas Supply Clause/PBR	4,623,541.84	
Asset Retirement Obligations		
Gas	2,147,968.32	
Electric	287,101.92	
MISO Schedule 10 Charges	603,177.99	
Purchased Gas Adjustment - Tennessee Gas	528,412.86	
Environmental Cost Recovery	440,516.00	
Customers' Advances for Construction		7,247,002.77
Line Extensions		
Gas	6,384,092.53	
Electric	851,608.23	
Other	11,302.01	
Asset Retirement Obligations		56,022,754.36
Electric	34,339,754.58	
Gas	21,575,399.91	
Common	107,599.87	
Other Deferred Credits	35,534,880.32	35,534,880.32
Miscellaneous Long-Term Liabilities		57,497,148.14
Long-Term Derivative Liabilities - ASC 815	51,845,397.27	
Workers' Compensation	5,651,750.87	
Accumulated Provision for Benefits		144,261,730.60
Postretirement Benefits - ASC 715	79,132,188.92	
Pension Payable	61,662,688.50	
Post Employment Benefits Payable	3,698,041.00	
Post Employment Medicare Subsidy	(231,187.82)	
Total Liabilities and Stockholders' Equity	$ 3,565,616,515.94	$ 3,565,616,515.94

December 22, 2011

Louisville Gas and Electric Company
Statement of Cash Flows
November 30, 2011

	Year to Date 2011	Year to Date 2010
Cash Flows from Operating Activities		
Net income	$ 112,033,253.59	$ 113,674,190.10
Items not requiring (providing) cash currently:		
Depreciation	130,109,969.12	120,215,941.59
Amortization	7,434,072.35	7,092,877.08
Deferred income taxes - net	41,421,288.15	23,163,894.75
Investment tax credit - net	(2,569,707.00)	(2,293,293.00)
Gain on disposal of assets	(1,187,093.47)	(33,760.40)
Other	22,880,403.77	26,448,006.35
Change in receivables	57,053,899.06	18,812,602.37
Change in inventory	8,260,958.42	(26,388,455.11)
Change in allowance inventory	(23,875.72)	1,298.76
Change in payables and accrued expenses	56,478,696.28	(37,378,119.41)
Change in regulatory assets	(35,043,560.79)	(45,805,603.35)
Change in regulatory liabilities	9,196,626.30	(33,320,929.21)
Change in other deferred debits	(30,969,354.26)	(576,727.85)
Change in other deferred credits	30,069,724.57	27,377,298.70
Pension and postretirement funding	(69,201,000.00)	(25,635,500.00)
Other	(10,433,925.92)	(19,201,555.04)
Net cash provided (used) by operating activities	325,510,374.45	146,152,166.33
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(137,823,656.05)	(106,698,940.24)
Gross additions to common utility plant - construction expenditures	(11,309,568.36)	(19,398,993.91)
Change in restricted cash	(9,056,453.92)	-
Proceeds received from sale of property	1,187,093.47	34,136.95
Change in non-hedging derivatives	-	7,053,368.10
Reissuance of reacquired bonds as Available for Sale debt securities	163,200,000.00	-
Other	(10,469,609.29)	-
Net cash provided (used) by investing activities	(4,272,194.15)	(119,010,429.10)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(2,012,315.91)	1,172,007,056.41
Payments for retirement of long-term debt	-	(970,000,000.00)
Net change in short-term debt	(174,876,000.00)	(170,400,400.00)
Dividends on common stock	(83,250,000.00)	(55,000,000.00)
Net cash provided (used) by financing activities	(260,138,315.91)	(23,393,343.59)
Net Increase (Decrease) in Cash and Cash Equivalents	61,099,864.39	3,748,393.64
Cash and Cash Equivalents at Beginning of Period	2,126,011.84	5,195,486.38
Cash and Cash Equivalents at End of Period	$ 63,225,876.23	$ 8,943,880.02

December 22, 2011

Louisville Gas and Electric 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						
Jefferson County 2000 Series A due 05/01/27 5.375%.......................	$ 111,979.18	$ 111,979.17	$ 1,231,770.88	$ 1,231,770.75	$ 1,343,750.05	$ 1,343,749.92
Trimble County 2000 Series A due 08/01/30 Var%............................	12,639.15	31,077.02	173,649.27	357,368.25	207,561.98	374,220.43
Jefferson County 2001 Series A due 09/01/26 Var%..........................	920.59	3,866.17	18,142.16	43,534.18	21,743.11	45,616.74
Jefferson County 2001 Series A due 09/01/27 Var%..........................	5,997.94	18,493.15	160,871.93	165,020.57	184,758.91	176,917.83
Jefferson County 2001 Series B due 11/01/27 Var%..........................	13,139.17	23,013.68	258,935.08	332,964.03	282,476.18	357,176.36
Trimble County 2001 Series A due 09/01/26 Var%............................	7,458.90	12,431.51	90,825.35	152,169.19	103,671.23	173,189.74
Trimble County 2001 Series A due 10/01/32 Var%............................	6,072.81	17,824.63	108,596.09	278,708.41	124,854.57	286,672.70
Trimble County 2001 Series B due 11/01/27 Var%............................	14,479.45	23,013.68	257,321.63	333,008.12	280,862.73	357,220.45
Louisville Metro 2003 Series A due 10/01/33 1.900%.......................	(12,729.93)	-	2,148,266.56	-	2,148,266.56	-
Louisville Metro 2005 Series A due 02/01/35 5.750%.......................	191,666.67	191,666.67	2,108,333.32	2,108,333.24	2,299,999.99	2,299,999.91
Louisville Metro 2007 Series A due 06/01/33 5.625%.......................	145,312.49	145,312.50	1,598,437.39	1,598,437.45	1,743,749.89	1,743,749.95
Louisville Metro 2007 Series B due 06/01/33 1.900%........................	55,733.34	-	592,631.16	-	592,631.16	-
Trimble County 2007 Series A due 06/01/33 4.600%.........................	230,000.00	230,000.00	2,530,000.00	2,530,000.00	2,760,000.00	2,760,000.00
Interest Rate Swaps..	652,215.65	642,132.85	7,077,535.27	6,995,296.79	7,780,578.79	7,613,057.44
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/15/15 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 11/15/40 5.125%..	1,217,187.50	608,593.75	13,389,062.50	608,593.75	14,606,250.00	608,593.75
Fidelia/PPL...	-	1,110,074.99	-	23,320,575.03	-	25,540,725.05
Revolving Credit Agreement..	-	276,285.01	185,005.01	276,285.01	503,398.34	276,285.01
Total..	2,990,614.58	3,615,035.62	35,653,341.93	40,501,335.61	39,047,053.49	44,126,446.12
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense...	159,607.07	128,013.07	1,938,256.75	283,338.92	2,108,292.84	298,857.24
Amortization of Loss on Reacquired Debt..	101,002.97	101,002.98	1,111,032.67	1,110,247.75	1,212,035.65	1,211,018.93
Total..	260,610.04	229,016.05	3,049,289.42	1,393,586.67	3,320,328.49	1,509,876.17
Other Interest Charges						
Customers' Deposits...	109,893.51	107,695.66	1,267,908.55	1,276,839.33	1,379,975.68	1,644,925.21
Other Tax Deficiencies..	-	-	14,000.00	(17,500.00)	14,000.00	(19,527.00)
Interest on DSM Cost Recovery..	1,469.28	1,172.58	13,882.97	25,152.22	15,145.99	27,053.21
Interest on Debt to Associated Companies..	-	1,280.89	9,461.72	261,773.55	10,110.05	289,469.49
Other Interest Expense...	84,367.49	53,450.90	1,060,806.82	782,298.46	1,221,278.53	815,179.08
Total..	195,730.28	163,600.03	2,366,060.06	2,328,563.56	2,640,510.25	2,757,099.99
Total Interest..	$ 3,446,954.90	$ 4,007,651.70	$ 41,068,691.41	$ 44,223,485.84	$ 45,007,892.23	$ 48,393,422.28

December 22, 2011

Louisville Gas and Electric 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..	$ 1,511,141.00	$ 272,746.10	$ 16,622,551.00	$ 12,503,490.80
Unemployment..	3,050.46	(15,960.06)	128,267.62	165,867.04
FICA..	587,380.50	290,566.48	7,108,643.72	6,422,837.14
Public Service Commission Fee..............................	162,886.60	161,096.90	1,781,014.44	1,775,537.04
Federal Income..	3,545,983.02	2,710,579.67	19,524,035.87	34,953,523.03
State Income..	661,075.08	494,330.64	9,233,906.44	5,820,742.44
Miscellaneous...	3,246.57	-	43,070.30	34,579.20
Total Charged to Operating Expense..........	6,474,763.23	3,913,359.73	54,441,489.39	61,676,576.69
Taxes Charged to Other Accounts...........................	518,352.48	(2,082,965.11)	1,551,536.30	10,289,586.85
Taxes Accrued on Intercompany Accounts.............	(32,626.71)	(220,852.23)	(1,860,038.39)	(2,639,897.28)
Total Taxes Charged..................................	$ 6,960,489.00	$ 1,609,542.39	$ 54,132,987.30	$ 69,326,266.26

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..	$ 11,354,131.66	$ 16,775,085.25	$ 11,571,701.44	$ 16,557,515.47
Unemployment..	54,386.05	88,783.52	142,352.04	817.53
FICA..	590,648.24	5,949,172.25	5,790,676.92	749,143.57
Federal Income..	(3,741,320.05)	18,091,002.53	4,674,143.00	9,675,539.48
State Income..	229,108.93	8,972,562.95	7,288,530.44	1,913,141.44
Kentucky Sales and Use Tax..................................	1,088,857.95	4,132,855.31	4,621,074.25	600,639.01
Miscellaneous...	22,339.97	123,525.49	113,098.74	32,766.72
Totals...	$ 9,598,152.75	$ 54,132,987.30	$ 34,201,576.83	$ 29,529,563.22

December 22, 2011

Louisville Gas and Electric Company
Summary of Utility Plant
November 30, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant In Service**						
Common						
Common General Plant	$ 159,884,459.36	$ 10,232,811.37	$ (696,298.11)	$ (30,818.06)	$ 9,505,695.20	$ 169,390,154.56
Common Intangible Plant	56,455,326.72	8,802,916.62	(1,661,801.58)	-	7,141,115.04	63,596,441.76
	216,339,786.08	19,035,727.99	(2,358,099.69)	(30,818.06)	16,646,810.24	232,986,596.32
Electric						
Electric Distribution	927,289,038.50	34,027,205.68	(6,799,229.79)	47,153.43	27,275,129.32	954,564,167.82
Electric General Plant	16,521,615.59	1,410,929.27	(1,981,092.03)	95,431.28	(474,731.48)	16,046,884.11
Electric Hydro Production	41,680,209.14	1,085,668.83	(229,943.87)	-	855,724.96	42,535,934.10
Electric Intangible Plant	2,340.29	-	-	-	-	2,340.29
Electric Other Production	229,401,033.01	5,823,654.94	(1,016,138.10)	38,429.14	4,845,945.98	234,246,978.99
Electric Steam Production	1,930,347,044.43	205,718,450.78	(26,466,191.93)	3,530,527.24	182,782,786.09	2,113,129,830.52
Electric Transmission	247,742,496.14	8,216,702.24	(1,586,170.73)	(47,153.43)	6,583,378.08	254,325,874.22
	3,392,983,777.10	256,282,611.74	(38,078,766.45)	3,664,387.66	221,868,232.95	3,614,852,010.05
Gas						
Gas Distribution	549,799,120.70	41,515,590.21	(613,524.96)	97,729.20	40,999,794.45	590,798,915.15
Gas General Plant	9,178,093.57	702,829.59	(1,090,634.01)	(185,857.43)	(573,661.85)	8,604,431.72
Gas Intangible Plant	1,187.49	-	-	-	-	1,187.49
Gas Storage	78,415,311.06	3,260,590.00	(1,654,671.28)	23,515.01	1,629,433.73	80,044,744.79
Gas Transmission	16,661,869.68	958,868.98	(20,299.95)	3,941,518.65	4,880,087.68	21,541,957.36
	654,055,582.50	46,437,878.78	(3,379,130.20)	3,876,905.43	46,935,654.01	700,991,236.51
Total 101 Accounts	4,263,379,145.68	321,756,218.51	(43,815,996.34)	7,510,475.03	285,450,697.20	4,548,829,842.88
105 **Plant Held For Future Use**						
Electric						
Electric Distribution	649,014.48	-	-	-	-	649,014.48
Electric Steam Production	4,182,559.70	-	-	(4,182,559.70)	(4,182,559.70)	-
	4,831,574.18	-	-	(4,182,559.70)	(4,182,559.70)	649,014.48
Total 105001	$ 4,831,574.18	$ -	$ -	$ (4,182,559.70)	$ (4,182,559.70)	$ 649,014.48

December 22, 2011

Louisville Gas and Electric Company
Summary of Utility Plant
November 30, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
106 **Completed Construction Not Classified**						
Common						
Common General Plant..	$ 597,158.63	$ 1,211,462.96	$ -	$ -	$ 1,211,462.96	$ 1,808,621.59
Common Intangible Plant......................................	2,714,931.36	(1,069,957.02)	-	-	(1,069,957.02)	1,644,974.34
	3,312,089.99	141,505.94	-	-	141,505.94	3,453,595.93
Electric						
Electric Distribution...	11,544,733.90	11,841,428.02	-	-	11,841,428.02	23,386,161.92
Electric General Plant..	50,763.87	(50,763.87)	-	-	(50,763.87)	-
Electric Hydro Production.....................................	16,952.26	(495.90)	-	-	(495.90)	16,456.36
Electric Intangible Plant...	-	-	-	-	-	-
Electric Other Production......................................	1,767,208.21	(1,727,573.21)	-	-	(1,727,573.21)	39,635.00
Electric Steam Production......................................	15,929,229.77	7,530,174.44	-	-	7,530,174.44	23,459,404.21
Electric Transmission...	35,045,472.82	2,057,741.58	-	-	2,057,741.58	37,103,214.40
	64,354,360.83	19,650,511.06	-	-	19,650,511.06	84,004,871.89
Gas						
Gas Distribution...	24,420,156.16	(7,120,324.18)	-	-	(7,120,324.18)	17,299,831.98
Gas General Plant..	126,992.17	93,185.49	-	-	93,185.49	220,177.66
Gas Intangible Plant...	-	-	-	-	-	-
Gas Storage..	951,426.06	(521,877.48)	-	-	(521,877.48)	429,548.58
Gas Transmission...	-	1,442,064.89	-	-	1,442,064.89	1,442,064.89
	25,498,574.39	(6,106,951.28)	-	-	(6,106,951.28)	19,391,623.11
Total 106 Accounts	93,165,025.21	13,685,065.72	-	-	13,685,065.72	106,850,090.93
117 **Gas Stored Underground-Noncurrent**						
Gas						
Gas Stored Nonrecoverable...................................	2,139,990.00	-	-	-	-	2,139,990.00
	2,139,990.00	-	-	-	-	2,139,990.00
Total 117001	2,139,990.00	-	-	-	-	2,139,990.00
121 **Nonutility Property**						
Common						
Non Utility Property..	75,239.56	-	-	-	-	75,239.56
	75,239.56	-	-	-	-	75,239.56
Total 121001	75,239.56	-	-	-	-	75,239.56
107 **Construction Work In Progress**						
Common..	21,243,879.89	(7,867,665.57)	-	-	(7,867,665.57)	13,376,214.32
Electric..	324,323,732.14	(165,950,481.76)	-	-	(165,950,481.76)	158,373,250.38
Gas..	39,756,306.91	3,023,277.45	-	-	3,023,277.45	42,779,584.36
	385,323,918.94	(170,794,869.88)	-	-	(170,794,869.88)	214,529,049.06
Total Plant (Non-CWIP).......................................	4,363,590,974.63	335,441,284.23	(43,815,996.34)	3,327,915.33	294,953,203.22	4,658,544,177.85
Total Plant + CWIP...	4,748,914,893.57	164,646,414.35	(43,815,996.34)	3,327,915.33	124,158,333.34	4,873,073,226.91
Total Plant + CWIP - Non Utility...........................	$ 4,748,839,654.01	$ 164,646,414.35	$ (43,815,996.34)	$ 3,327,915.33	$ 124,158,333.34	$ 4,872,997,987.35

December 22, 2011

Louisville Gas and Electric 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										
Common General Plant	$ (77,263,235.10)	$ (11,824,077.24)	$ 696,298.11	$ 30,818.06	$ -	$ -	$ -	$ -	$ -	$ (88,360,196.17)
Common General Plant - ARO	(343.19)	(1,888.70)	-	-	-	-	-	-	-	(2,231.89)
Electric Distribution	(277,000,365.75)	(15,950,490.18)	6,799,229.79	(382.60)	-	-	-	-	-	(286,152,008.74)
Electric Distribution - ARO	(1,256.54)	(5,531.03)	-	-	-	-	-	-	-	(6,787.57)
Electric General Plant	(12,910,034.19)	(395,180.76)	1,981,092.03	(95,431.28)	-	-	-	-	-	(11,419,554.20)
Electric Hydro Production	(9,718,276.66)	(516,508.06)	229,943.87	-	-	-	-	-	-	(10,004,840.85)
Electric Hydro Production - ARO	(364.10)	(1,602.81)	-	-	-	-	-	-	-	(1,966.91)
Electric Other Production	(60,282,055.17)	(7,507,383.77)	1,016,138.10	-	-	-	-	-	-	(66,773,300.84)
Electric Other Production - ARO	(192.68)	(1,013.58)	-	-	-	-	-	-	-	(1,206.26)
Electric Steam Production	(1,029,518,070.37)	(52,075,527.36)	25,733,986.89	-	-	-	-	-	-	(1,055,859,610.84)
Electric Steam Production - ARO	(204,061.94)	(1,901,516.46)	732,205.04	116,513.06	-	-	-	-	-	(1,256,860.30)
Electric Transmission	(119,192,606.75)	(4,024,940.40)	1,586,170.73	382.60	-	-	-	-	-	(121,630,993.82)
Electric Transmission - ARO	(41.40)	(182.27)	-	-	-	-	-	-	-	(223.67)
Gas Distribution	(125,049,477.23)	(10,627,569.92)	538,485.69	(13,332.40)	-	-	-	-	-	(135,151,893.86)
Gas Distribution - ARO	(49,734.93)	(346,862.41)	75,039.27	-	-	-	-	-	-	(321,558.07)
Gas General Plant	(6,299,629.20)	(296,365.13)	1,090,634.01	87,301.32	-	-	-	-	-	(5,418,059.00)
Gas Storage	(31,288,281.49)	(992,767.27)	1,259,265.82	(9,355.70)	-	-	-	-	-	(31,031,138.64)
Gas Storage - ARO	(39,466.10)	(595,142.15)	395,405.46	-	-	-	-	-	-	(239,202.79)
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(9,448,605.32)	(52,979.87)	20,299.95	-	-	-	-	-	-	(9,481,285.24)
Gas Transmission - ARO	-	(26,453.15)	-	-	-	-	-	-	-	(26,453.15)
Non Utility Property	(63,360.36)	-	-	-	-	-	-	-	-	(63,360.36)
	(1,758,329,458.47)	(107,143,982.52)	42,154,194.76	116,513.06	-	-	-	-	-	(1,823,202,733.17)
Cost Of Removal										
Common General Plant	(688,372.47)	(258,340.63)	-	-	-	-	332,962.76	-	-	(613,750.34)
Electric Distribution	(146,715,298.78)	(6,318,991.10)	-	(55.48)	-	-	3,860,670.88	-	-	(149,173,674.48)
Electric General Plant	3,866.64	-	-	-	-	-	-	-	-	3,866.64
Electric Hydro Production	736,907.70	(39,224.65)	-	-	-	-	38,351.42	-	-	736,034.47
Electric Other Production	(2,505,175.99)	(322,025.24)	-	-	-	-	320,969.80	-	-	(2,506,231.43)
Electric Steam Production	(94,783,295.15)	(15,576,945.58)	-	-	-	-	3,582,177.53	-	-	(106,778,063.20)
Electric Transmission	(24,538,454.78)	(1,295,265.42)	-	55.48	-	-	206,202.17	-	-	(25,627,462.55)
Gas Distribution	(60,212,131.14)	(3,007,432.41)	-	-	-	-	1,487,211.13	-	-	(61,732,352.42)
Gas General Plant	(0.02)	-	-	-	-	-	-	-	-	(0.02)
Gas Storage	(170,437.90)	(128,973.78)	-	-	-	-	573,971.38	-	-	274,559.70
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(3,016,813.95)	(13,108.44)	-	-	-	-	46,319.99	-	-	(2,983,602.40)
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	$ (331,889,205.84)	$ (26,960,307.25)	$ -	$ -	$ -	$ -	$ 10,448,837.06	$ -	$ -	$ (348,400,676.03)

December 22, 2011

Louisville Gas and Electric 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
Salvage										
Common General Plant	$ 278,074.55	$ 351.34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 278,425.89
Electric Distribution	17,535,024.98	1,281,008.55	-	-	-	-	-	(197,553.22)	-	18,618,480.31
Electric General Plant	138,281.25	2,118.05	-	-	-	-	-	-	-	140,399.30
Electric Hydro Production	376,638.17	-	-	-	-	-	-	-	-	376,638.17
Electric Other Production	(18,998.67)	-	-	-	-	-	-	-	-	(18,998.67)
Electric Steam Production	22,028,570.14	1,856,536.91	-	-	-	-	-	(34,636.38)	-	23,850,470.67
Electric Transmission	6,247,368.67	240,183.75	-	-	-	-	-	-	-	6,487,552.42
Gas Distribution	3,594,440.75	183,189.15	-	-	-	-	-	-	-	3,777,629.90
Gas General Plant	225,788.37	2,136.01	-	-	-	-	-	-	-	227,924.38
Gas Storage	269,933.04	15,765.36	-	-	-	-	-	-	-	285,698.40
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	217,923.11	4,915.66	-	-	-	-	-	-	-	222,838.77
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	50,893,044.36	3,586,204.78	-	-	-	-	-	(232,189.60)	-	54,247,059.54
Total Reserves										
Common	(77,737,236.57)	(12,083,955.23)	696,298.11	30,818.06	-	-	332,962.76	-	-	(88,761,112.87)
Electric	(1,730,321,891.37)	(102,552,481.41)	38,078,766.45	21,081.78	-	-	8,008,371.80	(232,189.60)	-	(1,786,998,342.35)
Gas	(231,266,492.01)	(15,881,648.35)	3,379,130.20	64,613.22	-	-	2,107,502.50	-	-	(241,596,894.44)
	(2,039,325,619.95)	(130,518,084.99)	42,154,194.76	116,513.06	-	-	10,448,837.06	(232,189.60)	-	(2,117,356,349.66)
Retirement Work In Progress										
Common	342,947.00	-	-	162,020.85	-	(332,962.76)	21,780.75	(20,894.00)	1,144.92	174,036.76
Electric	9,603,653.21	-	-	(78,968.13)	(1,142,636.19)	(7,201,791.25)	10,717,948.70	(479,247.66)	(516,368.43)	10,902,590.25
Gas	2,523,160.64	-	-	(23,759.86)	(1,053,809.06)	(1,311,698.78)	1,342,970.31	(7,015.24)	(2,703.32)	1,467,144.69
	12,469,760.85	-	-	59,292.86	(2,196,445.25)	(8,846,452.79)	12,082,699.76	(507,156.90)	(517,926.83)	12,543,771.70
YTD ACTIVITY	(2,026,855,859.10)	(130,518,084.99)	42,154,194.76	175,805.92	(2,196,445.25)	(8,846,452.79)	22,531,536.82	(739,346.50)	(517,926.83)	(2,104,812,577.96)
Amortization										
Common	(16,306,390.60)	(7,434,072.35)	1,661,801.58	-	-	-	-	-	-	(22,078,661.37)
Electric	(100.00)	-	-	-	-	-	-	-	-	(100.00)
Gas	(800.00)	-	-	-	-	-	-	-	-	(800.00)
AMORTIZATION TOTAL	(16,307,290.60)	(7,434,072.35)	1,661,801.58	-	-	-	-	-	-	(22,079,561.37)
Depreciation & Amortization Total	$ (2,043,163,149.70)	$ (137,952,157.34)	$ 43,815,996.34	$ 175,805.92	$ (2,196,445.25)	$ (8,846,452.79)	$ 22,531,536.82	$ (739,346.50)	$ (517,926.83)	$ (2,126,892,139.33)
Depr & Amort - Nonutility for Balance Sheet										(2,126,828,778.97)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)	$ 2,705,739,864.67									$ 2,746,169,208.38

December 22, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
November 30, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues.......................................	$ 79,790,596.68	$ -	$ 79,790,596.68
Gas Operating Revenues...	26,654,047.95	-	26,654,047.95
Total Operating Revenues..	106,444,644.63	-	106,444,644.63
Fuel for Electric Generation..	28,153,852.37	-	28,153,852.37
Power Purchased...	5,064,747.78	-	5,064,747.78
Gas Supply Expenses..	13,753,574.24	-	13,753,574.24
Other Operation Expenses...	19,493,999.54	-	19,493,999.54
Maintenance..	10,820,356.27	-	10,820,356.27
Depreciation..	11,890,425.36	-	11,890,425.36
Amortization Expense...	717,415.76	-	717,415.76
Regulatory Credits...	(413,283.37)	-	(413,283.37)
Taxes			
Federal Income...	3,545,983.02	-	3,545,983.02
State Income..	661,075.08	-	661,075.08
Deferred Federal Income - Net.................................	(18,861.57)	8,230.80	(10,630.77)
Deferred State Income - Net.....................................	279,395.94	1,501.06	280,897.00
Property and Other...	2,267,705.13	-	2,267,705.13
Amortization of Investment Tax Credit....................	(236,034.00)	-	(236,034.00)
Loss (Gain) from Disposition of Allowances...............	-	-	-
Accretion Expense..	230,714.66	-	230,714.66
Total Operating Expenses..	96,211,066.21	9,731.86	96,220,798.07
Net Operating Income...	10,233,578.42	(9,731.86)	10,223,846.56
Other Income Less Deductions.................................	127,698.96	-	127,698.96
Income Before Interest Charges................................	10,361,277.38	(9,731.86)	10,351,545.52
Interest on Long-Term Debt..	2,990,614.58	(25,017.63)	2,965,596.95
Amortization of Debt Expense - Net...........................	260,610.04	-	260,610.04
Other Interest Expenses...	195,730.28	-	195,730.28
Total Interest Charges..	3,446,954.90	(25,017.63)	3,421,937.27
Net Income..	$ 6,914,322.48	$ 15,285.77	$ 6,929,608.25

December 22, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
November 30, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues..	$ 974,948,348.67	$ -	$ 974,948,348.67
Gas Operating Revenues..	263,479,763.36	-	263,479,763.36
Total Operating Revenues...	1,238,428,112.03	-	1,238,428,112.03
Fuel for Electric Generation...	328,538,900.93	-	328,538,900.93
Power Purchased..	67,954,253.01	-	67,954,253.01
Gas Supply Expenses...	140,301,450.48	-	140,301,450.48
Other Operation Expenses...	216,517,844.55	27,884.66	216,545,729.21
Maintenance..	107,425,541.63	-	107,425,541.63
Depreciation..	130,109,969.12	-	130,109,969.12
Amortization Expense..	7,434,072.35	-	7,434,072.35
Regulatory Credits...	(5,292,975.68)	-	(5,292,975.68)
Taxes			
Federal Income..	19,524,035.87	-	19,524,035.87
State Income...	9,233,906.44	-	9,233,906.44
Deferred Federal Income - Net..................................	38,571,545.33	81,426.55	38,652,971.88
Deferred State Income - Net.....................................	143,524.54	14,849.84	158,374.38
Property and Other..	25,683,547.09	-	25,683,547.09
Amortization of Investment Tax Credit.....................	(2,569,707.00)	-	(2,569,707.00)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	-	(2,577.94)
Accretion Expense...	2,412,783.12	-	2,412,783.12
Total Operating Expenses...	1,085,986,113.84	124,161.05	1,086,110,274.89
Net Operating Income..	152,441,998.19	(124,161.05)	152,317,837.14
Other Income Less Deductions.................................	659,946.81	-	659,946.81
Income Before Interest Charges................................	153,101,945.00	(124,161.05)	152,977,783.95
Interest on Long-Term Debt...	35,653,341.93	(275,193.93)	35,378,148.00
Amortization of Debt Expense - Net............................	3,049,289.42	-	3,049,289.42
Other Interest Expenses...	2,366,060.06	-	2,366,060.06
Total Interest Charges...	41,068,691.41	(275,193.93)	40,793,497.48
Net Income...	$ 112,033,253.59	$ 151,032.88	$ 112,184,286.47

December 22, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
November 30, 2011

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……………………………	$ 877,862,183.07	$ 808,946,891.52	$ (808,763,535.33)	-	$ 69,098,647.74	$ 808,946,891.52
Add:						
Net Income (Loss) for Period…………………………	6,914,322.48	5,006,164.82	15,285.77	23,804.53	6,929,608.25	5,029,969.35
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	808,946,891.52	-	808,946,891.52
Common Dividends						
Common Stock Without Par Value………………	28,000,000.00	-	-	-	28,000,000.00	-
Balance at End of Period…………………………………	$ 856,776,505.55	$ 813,953,056.34	$ (808,748,249.56)	$ (808,923,086.99)	$ 48,028,255.99	$ 5,029,969.35

December 22, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
November 30, 2011

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period................................	$ 827,993,251.96	$ 755,278,866.24	$ (808,899,282.44)	$ -	$ 19,093,969.52	$ 755,278,866.24
Add:						
Net Income (Loss) for Period.............................	112,033,253.59	113,674,190.10	151,032.88	23,804.53	112,184,286.47	113,697,994.63
Deduct:						
Adjustment to Retained Earnings........................	-	-	-	808,946,891.52	-	808,946,891.52
Common Dividends						
Common Stock Without Par Value.................	83,250,000.00	55,000,000.00	-	-	83,250,000.00	55,000,000.00
Balance at End of Period.......................................	$ 856,776,505.55	$ 813,953,056.34	$ (808,748,249.56)	$ (808,923,086.99)	$ 48,028,255.99	$ 5,029,969.35

December 22, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
November 30, 2011

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period	$ 813,953,056.34	$ 741,439,450.95	$ (808,923,086.99)	$ -	$ 5,029,969.35	$ 741,439,450.95
Add:						
Net Income (Loss) for Period	126,073,449.21	127,513,605.39	174,837.43	23,804.53	126,248,286.64	127,537,409.92
Deduct:						
Adjustment to Retained Earnings	-	-	-	808,946,891.52	-	808,946,891.52
Common Dividends						
Common Stock Without Par Value	83,250,000.00	55,000,000.00	-	-	83,250,000.00	55,000,000.00
Balance at End of Period	$ 856,776,505.55	$ 813,953,056.34	$ (808,748,249.56)	$ (808,923,086.99)	$ 48,028,255.99	$ 5,029,969.35

December 22, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of November 30, 2011

Assets	Without Purchase Accounting	Purchase Accounting	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 4,872,997,987.35	$ -	$ 4,872,997,987.35
Less: Reserves for Depreciation and Amortization....	2,126,828,778.97	-	2,126,828,778.97
Total..	2,746,169,208.38	-	2,746,169,208.38
Investments			
Ohio Valley Electric Corporation.............................	594,286.00	-	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	-	11,879.20
Special Funds...	28,514,787.39	-	28,514,787.39
Total..	29,120,952.59	-	29,120,952.59
Current and Accrued Assets			
Cash..	34,195,977.48	-	34,195,977.48
Special Deposits..	-	-	-
Temporary Cash Investments...................................	29,029,898.75	-	29,029,898.75
Accounts Receivable - Less Reserve........................	114,669,412.44	-	114,669,412.44
Accounts Receivable from Associated Companies....	11,548,437.29	-	11,548,437.29
Materials and Supplies - At Average Cost			
Fuel..	55,707,094.47	-	55,707,094.47
Plant Materials and Operating Supplies.................	30,482,076.24	-	30,482,076.24
Stores Expense...	5,550,219.41	-	5,550,219.41
Gas Stored Underground.......................................	62,658,874.27	-	62,658,874.27
Emission Allowances...	26,604.68	-	26,604.68
Prepayments..	4,982,269.92	-	4,982,269.92
Miscellaneous Current and Accrued Assets..............	-	-	-
Total..	348,850,864.95	-	348,850,864.95
Deferred Debits and Other			
Unamortized Debt Expense......................................	13,447,248.44	(3,496,727.46)	9,950,520.98
Unamortized Loss on Bonds....................................	20,823,617.00	-	20,823,617.00
Accumulated Deferred Income Taxes.......................	26,355,404.03	72,399,448.49	98,754,852.52
Deferred Regulatory Assets.....................................	379,199,955.06	9,399,492.26	388,599,447.32
Other Deferred Debits..	1,649,265.49	164,818,885.26	166,468,150.75
Goodwill...	-	389,157,351.59	389,157,351.59
Total..	441,475,490.02	632,278,450.14	1,073,753,940.16
Total Assets..	$ 3,565,616,515.94	$ 632,278,450.14	$ 4,197,894,966.08

December 22, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of November 30, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting	Total
Proprietary Capital			
Common Stock	$ 425,170,424.09	$ -	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	-	835,888.64
Paid-In Capital	83,581,499.00	1,194,085,869.02	1,277,667,368.02
Other Comprehensive Income	-	-	-
Retained Earnings	856,776,505.55	(808,748,249.56)	48,028,255.99
Total Proprietary Capital	1,364,692,540.00	385,337,619.46	1,750,030,159.46
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	6,251,487.81	580,555,487.81
First Mortgage Bonds	531,308,220.78	-	531,308,220.78
LT Notes Payable to Associated Companies	-	-	-
Total Long-Term Debt	1,105,612,220.78	6,251,487.81	1,111,863,708.59
Total Capitalization	2,470,304,760.78	391,589,107.27	2,861,893,868.05
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies	-	-	-
Accounts Payable	81,283,596.90	-	81,283,596.90
Accounts Payable to Associated Companies	16,784,036.42	-	16,784,036.42
Customer Deposits	22,388,530.85	-	22,388,530.85
Taxes Accrued	29,529,563.22	-	29,529,563.22
Dividends Declared	28,000,000.00	-	28,000,000.00
Interest Accrued	5,951,860.54	-	5,951,860.54
Miscellaneous Current and Accrued Liabilities	19,807,279.09	-	19,807,279.09
Total	203,744,867.02	-	203,744,867.02
Deferred Credits and Other			
Accumulated Deferred Income Taxes	487,425,528.06	69,967,692.81	557,393,220.87
Investment Tax Credit	42,954,869.13	-	42,954,869.13
Regulatory Liabilities	60,622,974.76	164,818,885.26	225,441,860.02
Customer Advances for Construction	7,247,002.77	-	7,247,002.77
Asset Retirement Obligations	56,022,754.36	-	56,022,754.36
Other Deferred Credits	35,534,880.32	5,902,764.80	41,437,645.12
Miscellaneous Long-Term Liabilities	57,497,148.14	-	57,497,148.14
Misc Long-Term Liab Due to Assoc Cos	-	-	-
Accum Provision for Postretirement Benefits	144,261,730.60	-	144,261,730.60
Total	891,566,888.14	240,689,342.87	1,132,256,231.01
Total Liabilities and Stockholders' Equity	$ 3,565,616,515.94	$ 632,278,450.14	$ 4,197,894,966.08

December 22, 2011

LOUISVILLE GAS AND ELECTRIC COMPANY

Financial Reports

October 31, 2011

Index
Financial and Operating Reports

Louisville Gas and Electric 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.

Louisville Gas and Electric Company
Comparative Statement of Income
October 31, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 79,332,461.18	$ 70,892,836.80	$ 8,439,624.38	11.90
Gas Operating Revenues...	18,830,221.33	15,647,671.54	3,182,549.79	20.34
Total Operating Revenues...	98,162,682.51	86,540,508.34	11,622,174.17	13.43
Fuel for Electric Generation...	26,589,929.51	28,082,990.38	(1,493,060.87)	(5.32)
Power Purchased..	7,628,086.41	4,132,725.97	3,495,360.44	84.58
Gas Supply Expenses...	9,674,278.22	7,114,021.31	2,560,256.91	35.99
Other Operation Expenses..	19,563,220.37	18,959,395.17	603,825.20	3.18
Maintenance..	10,777,128.87	10,067,345.59	709,783.28	7.05
Depreciation..	11,928,154.12	10,888,974.41	1,039,179.71	9.54
Amortization Expense...	705,150.17	626,243.97	78,906.20	12.60
Regulatory Credits..	(468,815.78)	(268,905.96)	(199,909.82)	(74.34)
Taxes				
Federal Income...	2,128,387.52	7,914,704.51	(5,786,316.99)	(73.11)
State Income...	365,732.29	2,876,833.06	(2,511,100.77)	(87.29)
Deferred Federal Income - Net.................................	317,260.52	(7,828,775.65)	8,146,036.17	104.05
Deferred State Income - Net......................................	(182,282.46)	(4,544,813.59)	4,362,531.13	95.99
Property and Other..	2,262,495.73	2,288,487.70	(25,991.97)	(1.14)
Investment Tax Credit...	-	-	-	-
Amortization of Investment Tax Credit.....................	(236,034.00)	(208,481.00)	(27,553.00)	(13.22)
Loss (Gain) from Disposition of Allowances...............	-	-	-	-
Accretion Expense..	230,794.03	175,681.78	55,112.25	31.37
Total Operating Expenses...	91,283,485.52	80,276,427.65	11,007,057.87	13.71
Net Operating Income..	6,879,196.99	6,264,080.69	615,116.30	9.82
Other Income Less Deductions.................................	(6,213.08)	(499,297.17)	493,084.09	98.76
Income Before Interest Charges................................	6,872,983.91	5,764,783.52	1,108,200.39	19.22
Interest on Long-Term Debt...	3,375,732.58	3,690,227.22	(314,494.64)	(8.52)
Amortization of Debt Expense - Net............................	295,947.81	116,549.81	179,398.00	153.92
Other Interest Expenses..	264,952.62	170,790.07	94,162.55	55.13
Total Interest Charges...	3,936,633.01	3,977,567.10	(40,934.09)	(1.03)
Net Income..	$ 2,936,350.90	$ 1,787,216.42	$ 1,149,134.48	64.30

November 21, 2011

Louisville Gas and Electric Company
Comparative Statement of Income
October 31, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 895,157,751.99	$ 846,385,743.97	$ 48,772,008.02	5.76
Gas Operating Revenues...	236,825,715.41	216,877,229.81	19,948,485.60	9.20
Total Operating Revenues...	1,131,983,467.40	1,063,262,973.78	68,720,493.62	6.46
Fuel for Electric Generation...	300,385,048.56	305,478,205.94	(5,093,157.38)	(1.67)
Power Purchased..	62,889,505.23	44,991,310.91	17,898,194.32	39.78
Gas Supply Expenses..	126,547,876.24	115,155,736.19	11,392,140.05	9.89
Other Operation Expenses..	197,023,845.01	187,063,874.63	9,959,970.38	5.32
Maintenance..	96,605,185.36	86,924,963.79	9,680,221.57	11.14
Depreciation..	118,219,543.76	109,328,647.16	8,890,896.60	8.13
Amortization Expense...	6,716,656.59	6,461,501.83	255,154.76	3.95
Regulatory Credits..	(4,879,692.31)	(3,539,747.74)	(1,339,944.57)	(37.85)
Taxes				
Federal Income...	15,978,052.85	32,242,943.36	(16,264,890.51)	(50.44)
State Income...	8,572,831.36	5,326,411.80	3,246,419.56	60.95
Deferred Federal Income - Net.................................	38,590,406.90	14,485,407.74	24,104,999.16	166.41
Deferred State Income - Net......................................	(135,871.40)	1,367,098.28	(1,502,969.68)	(109.94)
Property and Other...	23,415,841.96	20,193,861.80	3,221,980.16	15.96
Investment Tax Credit..	-	-	-	-
Amortization of Investment Tax Credit.....................	(2,333,673.00)	(2,084,812.00)	(248,861.00)	(11.94)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	2,182,068.46	2,849,582.80	(667,514.34)	(23.43)
Total Operating Expenses...	989,775,047.63	926,210,526.35	63,564,521.28	6.86
Net Operating Income..	142,208,419.77	137,052,447.43	5,155,972.34	3.76
Other Income Less Deductions.................................	532,247.85	11,831,411.99	(11,299,164.14)	(95.50)
Income Before Interest Charges................................	142,740,667.62	148,883,859.42	(6,143,191.80)	(4.13)
Interest on Long-Term Debt...	32,662,727.35	36,886,299.99	(4,223,572.64)	(11.45)
Amortization of Debt Expense - Net............................	2,788,679.38	1,164,570.62	1,624,108.76	139.46
Other Interest Expenses..	2,170,329.78	2,164,963.53	5,366.25	0.25
Total Interest Charges...	37,621,736.51	40,215,834.14	(2,594,097.63)	(6.45)
Net Income..	$ 105,118,931.11	$ 108,668,025.28	$ (3,549,094.17)	(3.27)

November 21, 2011

Louisville Gas and Electric 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..	$ 1,064,383,574.99	$ 987,426,810.02	$ 76,956,764.97	7.79
Gas Operating Revenues...	322,895,841.48	286,856,623.90	36,039,217.58	12.56
Total Operating Revenues...	1,387,279,416.47	1,274,283,433.92	112,995,982.55	8.87
Fuel for Electric Generation...	363,463,168.96	355,512,230.98	7,950,937.98	2.24
Power Purchased..	72,277,913.01	55,314,082.51	16,963,830.50	30.67
Gas Supply Expenses..	180,395,748.10	161,705,875.59	18,689,872.51	11.56
Other Operation Expenses..	236,772,974.95	222,805,316.80	13,967,658.15	6.27
Maintenance..	121,381,326.65	106,689,424.32	14,691,902.33	13.77
Depreciation..	140,100,899.87	130,975,973.26	9,124,926.61	6.97
Amortization Expense...	7,982,143.66	7,868,576.94	113,566.72	1.44
Regulatory Credits..	(5,609,676.02)	(3,895,700.94)	(1,713,975.08)	(44.00)
Taxes				
Federal Income..	12,609,716.67	50,079,566.76	(37,469,850.09)	(74.82)
State Income...	9,293,586.99	6,074,380.37	3,219,206.62	53.00
Deferred Federal Income - Net.................................	51,772,004.16	(10,671,247.21)	62,443,251.37	585.15
Deferred State Income - Net......................................	867,054.76	(843,743.85)	1,710,798.61	202.76
Property and Other..	25,793,603.98	22,591,490.79	3,202,113.19	14.17
Investment Tax Credit...	-	703,437.35	(703,437.35)	(100.00)
Amortization of Investment Tax Credit.....................	(2,750,635.00)	(2,581,586.48)	(169,048.52)	(6.55)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	2,616,591.29	3,176,256.53	(559,665.24)	(17.62)
Total Operating Expenses...	1,216,963,844.09	1,105,469,873.58	111,493,970.51	10.09
Net Operating Income..	170,315,572.38	168,813,560.34	1,502,012.04	0.89
Other Income Less Deductions.................................	(581,691.80)	1,661,732.21	(2,243,424.01)	(135.01)
Income Before Interest Charges................................	169,733,880.58	170,475,292.55	(741,411.97)	(0.43)
Interest on Long-Term Debt...	39,671,474.53	43,435,399.16	(3,763,924.63)	(8.67)
Amortization of Debt Expense - Net............................	3,288,734.50	1,525,008.38	1,763,726.12	115.65
Other Interest Expenses..	2,608,380.00	2,819,617.16	(211,237.16)	(7.49)
Total Interest Charges...	45,568,589.03	47,780,024.70	(2,211,435.67)	(4.63)
Net Income..	$ 124,165,291.55	$ 122,695,267.85	$ 1,470,023.70	1.20

November 21, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings
October 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period..	$ 874,925,832.17	$ 807,159,675.10	$ 827,993,251.96	$ 755,278,866.24	$ 808,946,891.52	$ 741,251,623.67
Add:						
Net Income for Period..	2,936,350.90	1,787,216.42	105,118,931.11	108,668,025.28	124,165,291.55	122,695,267.85
Deduct:						
Common Dividends						
Common Stock Without Par Value.....................	-	-	55,250,000.00	55,000,000.00	55,250,000.00	55,000,000.00
Balance at End of Period...	$ 877,862,183.07	$ 808,946,891.52	$ 877,862,183.07	$ 808,946,891.52	$ 877,862,183.07	$ 808,946,891.52

November 21, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of October 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,854,087,312.73	$ 4,689,347,414.37
Less: Reserves for Depreciation and Amortization	2,119,839,274.24	2,030,781,175.75
Total	2,734,248,038.49	2,658,566,238.62
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	29,513,085.39	21,156,261.72
Total	30,119,250.59	21,762,426.92
Current and Accrued Assets		
Cash	42,810,271.73	3,825,761.11
Special Deposits	557,339.76	694,647.22
Temporary Cash Investments	31,125,914.89	119.71
Accounts Receivable - Less Reserve	105,912,233.14	120,885,025.11
Accounts Receivable from Associated Companies	11,234,858.52	15,918,666.44
Materials and Supplies - At Average Cost		
Fuel	59,220,758.36	69,001,447.80
Plant Materials and Operating Supplies	30,813,805.38	29,262,178.89
Stores Expense	5,577,590.22	4,866,562.11
Gas Stored Underground	66,152,494.75	69,292,419.44
Emission Allowances	24,614.20	2,936.23
Prepayments	5,460,672.11	4,620,700.76
Miscellaneous Current and Accrued Assets	607,780.56	1,053,692.59
Total	359,498,333.62	319,424,157.41
Deferred Debits and Other		
Unamortized Debt Expense	13,557,379.65	3,698,835.99
Unamortized Loss on Bonds	20,924,619.95	22,136,655.35
Accumulated Deferred Income Taxes	26,434,331.06	49,392,552.07
Deferred Regulatory Assets	376,302,783.78	398,998,957.42
Other Deferred Debits	1,365,988.12	2,639,042.93
Total	438,585,102.56	476,866,043.76
Total Assets	$ 3,562,450,725.26	$ 3,476,618,866.71

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	877,862,183.07	808,946,891.52
Total Proprietary Capital	1,385,778,217.52	1,316,862,925.97
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds	531,284,899.12	-
LT Notes Payable to Associated Companies	-	485,000,000.00
Total Long-Term Debt	1,105,588,899.12	896,104,000.00
Total Capitalization	2,491,367,116.64	2,212,966,925.97
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	142,309,400.00
Accounts Payable	91,057,684.20	108,349,293.44
Accounts Payable to Associated Companies	13,798,613.52	51,218,385.36
Customer Deposits	22,425,873.82	23,673,139.66
Taxes Accrued	23,483,954.44	12,074,347.15
Interest Accrued	13,345,579.80	4,316,975.16
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	19,943,526.53	16,881,002.06
Total	184,055,232.31	358,822,542.83
Deferred Credits and Other		
Accumulated Deferred Income Taxes	487,243,920.69	454,586,900.11
Investment Tax Credit	43,190,903.13	45,941,538.13
Regulatory Liabilities	61,440,578.69	51,659,503.79
Customer Advances for Construction	8,022,178.51	8,451,907.43
Asset Retirement Obligations	55,792,039.70	65,149,934.69
Other Deferred Credits	32,850,657.34	5,955,456.28
Miscellaneous Long-Term Liabilities	54,212,429.21	49,962,421.48
Accum Provision for Postretirement Benefits	144,275,669.04	223,121,736.00
Total	887,028,376.31	904,829,397.91
Total Liabilities and Stockholders' Equity	$ 3,562,450,725.26	$ 3,476,618,866.71

November 21, 2011

Louisville Gas and Electric 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..	75,000,000	21,294,223	$ 425,170,424.09	
Less: Common Stock Expense..			835,888.64	
Paid-In Capital..			83,581,499.00	
Other Comprehensive Income..			-	
Retained Earnings..			877,862,183.07	
Total Proprietary Capital...			1,385,778,217.52	55.62
Long-Term Debt				
Pollution Control Bonds..				
Jefferson County 2000 Series A due 05/01/27 5.375%................			25,000,000.00	
Trimble County 2000 Series A due 08/01/30 Var%.....................			83,335,000.00	
Jefferson County 2001 Series A due 09/01/26 Var%..................			22,500,000.00	
Jefferson County 2001 Series A due 09/01/27 Var%...................			10,104,000.00	
Jefferson County 2001 Series B due 11/01/27 Var%..................			35,000,000.00	
Trimble County 2001 Series A due 09/01/26 Var%.....................			27,500,000.00	
Trimble County 2001 Series A due 10/01/32 Var%.....................			41,665,000.00	
Trimble County 2001 Series B due 11/01/27 Var%.....................			35,000,000.00	
Louisville Metro 2003 Series A due 10/01/33 1.900%.................			128,000,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%.................			40,000,000.00	
Louisville Metro 2007 Series A due 06/01/33 5.625%.................			31,000,000.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%.................			35,200,000.00	
Trimble County 2007 Series A due 06/01/33 4.600%..................			60,000,000.00	
Total Pollution Control Bonds..			574,304,000.00	23.05
First Mortgage Bonds..				
First Mortgage Bond Due 11/15/15 1.625%..................................			250,000,000.00	
First Mortgage Bond Due 11/15/40 5.125%..................................			285,000,000.00	
Total First Mortgage Bonds..			535,000,000.00	21.48
Less: First Mortgage Bonds Debt Discount.....................................				
First Mortgage Bond Due 11/15/15 1.625%..................................			(713,354.19)	
First Mortgage Bond Due 11/15/40 5.125%..................................			(3,001,746.69)	
			(3,715,100.88)	-0.15
Total First Mortgage Bonds - Net of Debt Discount........................			531,284,899.12	21.33
Total Capitalization..			$ 2,491,367,116.64	100.00

November 21, 2011

Louisville Gas and Electric Company
Summary Trial Balance
October 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 4,854,087,312.73	$ 4,854,087,312.73
Reserves for Depreciation and Amortization		(2,119,839,274.24)
Depreciation of Plant		
Electric	(1,771,932,715.04)	
Gas	(239,128,005.43)	
Common	(87,416,408.16)	
Amortization of Plant		
Common	(21,361,245.61)	
Gas	(800.00)	
Electric	(100.00)	
Investments		30,119,250.59
Special Funds	29,513,085.39	
Ohio Valley Electric Corporation	594,286.00	
Nonutility Property	11,879.20	
Cash	42,810,271.73	42,810,271.73
Special Deposits		557,339.76
MAN Margin Call	557,339.76	
Temporary Cash Investments	31,125,914.89	31,125,914.89
Accounts Receivable - Less Reserve		105,912,233.14
Customers - Active	51,413,621.95	
Unbilled Revenues	45,256,689.25	
Wholesale Sales	3,492,032.50	
IMPA	2,247,470.14	
IMEA	2,171,868.97	
Sundry Accounts Receivable	1,210,558.85	
Transmission Sales	488,285.42	
Damage Claims	397,898.09	
Mutual Aid	154,199.49	
Bechtel Liquidated Damages	5,890.00	
Other	901,963.89	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	5,166,033.63	
Accrual	(4,202,615.40)	
Reserve	(1,680,010.00)	
Recoveries	(964,594.11)	
A/R Miscellaneous	(147,059.53)	
Accounts Receivable from Associated Companies		11,234,858.52
LG&E - KU Energy Services/Kentucky Utilities	10,993,592.18	
PPL Energy Funding	241,266.34	
Fuel		59,220,758.36
Coal 1,235,384.56 Tons @ $46.65; MMBtu 27,985,499.70 @ 205.93¢	57,631,482.91	
Gas Pipeline 4,400 Mcf @ 267.87¢	1,178,644.37	
Fuel Oil 161,214.15 Gallons @ 254.71¢	410,631.08	
Plant Materials and Operating Supplies		30,813,805.38
Regular Materials and Supplies	30,025,832.76	
Limestone 93,864.94 Tons @ $8.39	787,972.62	
Stores Expense Undistributed	5,577,590.22	5,577,590.22
Gas Stored Underground - Current		66,152,494.75
Gas Stored Underground* 14,239,902 Mcf (14.73 psia) @ $4.65	66,152,494.75	
Emission Allowances	24,614.20	24,614.20

November 21, 2011

Louisville Gas and Electric Company
Summary Trial Balance
October 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Prepayments		$ 5,460,672.11
Insurance	2,306,757.19	
Taxes	1,303,092.86	
Rights of Way	226,666.71	
Risk Management and Workers Compensation	90,000.00	
Other	1,534,155.35	
Miscellaneous Current Assets		607,780.56
Derivative Asset - Non-Hedging	607,780.56	
Unamortized Debt Expense		13,557,379.65
Trimble County 2000 Series A due 08/01/30 Var%	725,763.26	
Jefferson County 2001 Series A due 09/01/26 Var%	147,202.62	
Jefferson County 2001 Series A due 09/01/27 Var%	322,881.16	
Jefferson County 2001 Series B due 11/01/27 Var%	175,924.00	
Trimble County 2001 Series A due 09/01/26 Var%	160,051.42	
Trimble County 2001 Series B due 11/01/27 Var%	175,952.86	
Trimble County 2002 Series A due 10/01/32 Var%	778,547.89	
Louisville Metro 2003 Series A Due 10/01/33 1.900%	435,846.27	
Louisville Metro 2007 Series B Due 06/01/33 1.900%	167,391.91	
Trimble County 2007 Series A due 06/01/33 4.600%	1,025,951.06	
First Mortgage Bond due 11/15/15 1.625%	2,096,843.39	
First Mortgage Bond due 11/15/40 5.125%	3,452,539.58	
Revolving Credit Agreement	3,892,484.23	
Unamortized Loss on Bonds	20,924,619.95	20,924,619.95
Accumulated Deferred Income Taxes		26,434,331.06
Federal		
Electric	24,512,783.64	
Gas	(3,208,377.50)	
State		
Electric	5,688,893.31	
Gas	(558,968.39)	
Regulatory Assets		376,302,783.78
Pension and Postretirement Benefits	213,180,670.00	
Interest Rate Swap Ineffectiveness	52,587,340.67	
2009 Winter Storm	38,358,592.29	
2008 Wind Storm	20,597,791.19	
Deferred Taxes - ASC 740		
Federal		
Electric	12,544,305.85	
State		
Electric	2,287,715.35	
Swap Termination	8,980,301.10	
Asset Retirement Obligations		
Electric	8,287,974.33	
Gas	937,803.80	
Common	7,779.37	
2011 Summer Storm	7,692,478.68	
Gas Supply Clause/PBR	4,521,139.90	
Fuel Adjustment Clause	3,264,000.00	
MISO Exit Fee	884,605.10	
Rate Case Expenses	880,203.32	
KCCS Funding	603,652.85	
EKPC FERC Transmission Costs	395,668.88	
CMRG Funding	170,730.00	
General Management Audit	120,031.10	
Other Deferred Debits	1,365,988.12	1,365,988.12
Total Assets	$ 3,562,450,725.26	$ 3,562,450,725.26

* Excludes:

	$	Mcf
Non-recoverable Base Gas	9,648,855.00	7,880,000
Recoverable Base Gas	2,139,990.00	2,930,000
	11,788,845.00	10,810,000

November 21, 2011

Louisville Gas and Electric Company
Summary Trial Balance
October 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 1,385,778,217.52
Common Stock	425,170,424.09	
Less: Common Stock Expense	835,888.64	
Paid-In Capital	83,581,499.00	
Retained Earnings	877,862,183.07	
Pollution Control Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,284,899.12	531,284,899.12
Accounts Payable		91,057,684.20
Regular	87,655,566.08	
Salaries and Wages Accrued	3,371,949.68	
Employee Withholdings Payable	30,168.44	
Accounts Payable to Associated Companies		13,798,613.52
LG&E - KU Energy Services/Kentucky Utilities	13,798,613.52	
Customers' Deposits	22,425,873.82	22,425,873.82
Taxes Accrued	23,483,954.44	23,483,954.44
Interest Accrued		13,345,579.80
Jefferson County 2000 Series A due 05/01/27 5.375%	671,875.00	
Trimble County 2000 Series A due 08/01/30 Var%	2,500.05	
Jefferson County 2001 Series A due 09/01/26 Var%	4,068.49	
Jefferson County 2001 Series A due 09/01/27 Var%	275.05	
Jefferson County 2001 Series B due 11/01/27 Var%	21,565.75	
Trimble County 2001 Series A due 09/01/26 Var%	5,447.26	
Trimble County 2001 Series A due 10/01/32 Var%	1,232.83	
Trimble County 2001 Series B due 11/01/27 Var%	20,342.47	
Louisville Metro 2003 Series A due 10/01/33 1.900%	202,666.67	
Louisville Metro 2005 Series A due 02/01/35 5.750%	568,611.11	
Louisville Metro 2007 Series A due 06/01/33 5.625%	726,562.50	
Louisville Metro 2007 Series B due 06/01/33 1.900%	280,524.44	
Trimble County 2007 Series A due 06/01/33 4.600%	1,150,000.00	
Interest Rate Swaps	607,869.63	
First Mortgage Bond due 11/15/15 1.625%	1,873,263.89	
First Mortgage Bond due 11/15/40 5.125%	6,735,104.17	
Customers' Deposits	444,578.86	
Interest Accrued on Tax Liabilities	14,000.00	
Other	15,091.63	
Miscellaneous Current and Accrued Liabilities		19,943,526.53
Vacation Pay Accrued	6,543,183.42	
Customer Overpayments	4,210,470.38	
ASC 815 Derivative Liability	4,026,662.33	
No-Notice Gas Payable	1,656,127.03	
Derivative Liabilities - Non-Hedging	941,362.60	
Tax Collections Payable	841,551.05	
Postretirement Benefits - Current	624,694.04	
Unearned Revenue	526,661.05	
Home Energy Assistance	349,763.20	
Service Deposit Refund Payable	99,934.76	
Other	123,116.67	

Louisville Gas and Electric Company
Summary Trial Balance
October 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Accumulated Deferred Income Taxes		$ 487,243,920.69
Federal		
Electric	343,771,978.17	
Gas	78,332,616.49	
State		
Electric	52,708,885.02	
Gas	12,430,441.01	
Investment Tax Credit		43,190,903.13
Advanced Coal Credit	23,243,223.00	
Job Development Credit		
Electric	19,368,923.98	
Gas	578,756.15	
Regulatory Liabilities		61,440,578.69
Deferred Taxes		
Federal		
Electric	40,767,799.91	
Gas	(11,454,754.66)	
State		
Electric	17,887,391.80	
Gas	(56,905.77)	
DSM Cost Recovery	5,197,793.32	
Gas Supply Clause/PBR	5,155,745.33	
Asset Retirement Obligations		
Gas	2,146,434.25	
Electric	280,924.28	
MISO Schedule 10 Charges	579,598.38	
Purchased Gas Adjustment - Tennessee Gas	557,213.85	
Environmental Cost Recovery	379,338.00	
Customers' Advances for Construction		8,022,178.51
Line Extensions		
Gas	6,508,991.09	
Electric	851,608.23	
Customer Advances - Museum Plaza	597,032.17	
Other	64,547.02	
Asset Retirement Obligations		55,792,039.70
Electric	34,205,586.19	
Gas	21,479,344.56	
Common	107,108.95	
Other Deferred Credits	32,850,657.34	32,850,657.34
Miscellaneous Long-Term Liabilities		54,212,429.21
Long-Term Derivative Liabilities - ASC 815	48,560,678.34	
Workers' Compensation	5,651,750.87	
Accumulated Provision for Benefits		144,275,669.04
Postretirement Benefits - ASC 715	79,146,127.36	
Pension Payable	61,662,688.50	
Post Employment Benefits Payable	3,698,041.00	
Post Employment Medicare Subsidy	(231,187.82)	
Total Liabilities and Stockholders' Equity	$ 3,562,450,725.26	$ 3,562,450,725.26

November 21, 2011

Louisville Gas and Electric Company
Statement of Cash Flows
October 31, 2011

	Year to Date 2011	Year to Date 2010
Cash Flows from Operating Activities		
Net income	$ 105,118,931.11	$ 108,668,025.28
Items not requiring (providing) cash currently:		
Depreciation	118,219,543.76	109,328,647.16
Amortization	6,716,656.59	6,461,501.83
Deferred income taxes - net	41,160,753.75	23,163,894.75
Investment tax credit - net	(2,333,673.00)	(2,084,812.00)
Gain on disposal of assets	(66,949.93)	(33,760.40)
Other	17,583,177.08	30,071,464.03
Change in receivables	66,489,794.25	13,508,700.26
Change in inventory	805,253.94	(22,512,088.44)
Change in allowance inventory	(21,885.24)	1,234.77
Change in payables and accrued expenses	31,898,374.24	9,255,452.77
Change in regulatory assets	(32,146,389.51)	(79,008,862.71)
Change in regulatory liabilities	10,014,230.23	(33,247,704.79)
Change in other deferred debits	(27,622,036.94)	(403,573.41)
Change in other deferred credits	27,385,501.59	(2,196,202.27)
Pension and postretirement funding	(69,201,000.00)	(25,635,500.00)
Other	(6,465,289.40)	49,924,149.56
Net cash provided (used) by operating activities	287,534,992.52	185,260,566.39
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(119,833,339.51)	(87,400,134.28)
Gross additions to common utility plant - construction expenditures	(8,125,994.98)	(16,987,253.01)
Proceeds received from sales of property	66,949.93	34,136.95
Change in restricted cash	(10,054,751.92)	-
Change in derivatives	-	840,645.25
Reissuance of reacquired bonds as Available for Sale debt securities	163,200,000.00	-
Other	(8,865,519.57)	-
Net cash provided (used) by investing activities	16,387,343.95	(103,512,605.09)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(1,986,161.69)	(26,566.86)
Net change in short-term debt	(174,876,000.00)	(28,091,000.00)
Dividends on common stock	(55,250,000.00)	(55,000,000.00)
Net cash provided (used) by financing activities	(232,112,161.69)	(83,117,566.86)
Net Increase (Decrease) in Cash and Cash Equivalents	71,810,174.78	(1,369,605.56)
Cash and Cash Equivalents at Beginning of Period	2,126,011.84	5,195,486.38
Cash and Cash Equivalents at End of Period	$ 73,936,186.62	$ 3,825,880.82

November 21, 2011

Louisville Gas and Electric 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						
Jefferson County 2000 Series A due 05/01/27 5.375%.......................	$ 111,979.18	$ 111,979.17	$ 1,119,791.70	$ 1,119,791.58	$ 1,343,750.04	$ 1,343,749.92
Trimble County 2000 Series A due 08/01/30 Var%............................	12,916.93	25,058.37	161,010.12	326,291.23	225,999.85	360,921.53
Jefferson County 2001 Series A due 09/01/26 Var%..........................	892.52	4,392.43	17,221.57	39,668.01	24,688.69	43,642.27
Jefferson County 2001 Series A due 09/01/27 Var%..........................	6,780.82	19,109.60	154,873.99	146,527.42	197,254.12	175,993.17
Jefferson County 2001 Series B due 11/01/27 Var%..........................	16,485.20	31,404.11	245,795.91	309,950.35	292,350.69	362,929.80
Trimble County 2001 Series A due 09/01/26 Var%............................	7,481.50	12,431.51	83,366.45	139,737.68	108,643.84	181,100.69
Trimble County 2001 Series A due 10/01/32 Var%............................	5,228.10	17,514.14	102,523.28	260,883.78	136,606.39	277,443.63
Trimble County 2001 Series B due 11/01/27 Var%............................	16,349.32	31,116.44	242,842.18	309,994.44	289,396.96	362,973.88
Louisville Metro 2003 Series A due 10/01/33 1.900%........................	411,307.71	-	2,160,996.49	-	2,160,996.49	(688,312.42)
Louisville Metro 2005 Series A due 02/01/35 5.750%........................	191,666.67	191,666.67	1,916,666.65	1,916,666.57	2,299,999.99	2,299,999.91
Louisville Metro 2007 Series A due 06/01/33 5.625%........................	145,312.49	145,312.50	1,453,124.90	1,453,124.95	1,743,749.90	1,743,749.95
Louisville Metro 2007 Series B due 06/01/33 1.900%........................	55,733.34	-	536,897.82	-	536,897.82	-
Trimble County 2007 Series A due 06/01/33 4.600%..........................	230,000.00	230,000.00	2,300,000.00	2,300,000.00	2,760,000.00	2,760,000.00
Interest Rate Swaps...	607,869.63	641,092.27	6,425,319.62	6,353,163.94	7,770,495.99	7,560,406.78
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/15/15 1.625%..	338,541.67	-	3,385,416.66	-	3,893,229.17	-
First Mortgage Bond due 11/15/40 5.125%..	1,217,187.50	-	12,171,875.00	-	13,997,656.25	-
Fidelia/PPL...	-	2,229,150.01	-	22,210,500.04	1,110,074.99	26,650,800.05
Revolving Credit Agreement..	-	-	185,005.01	-	779,683.35	-
Total..	3,375,732.58	3,690,227.22	32,662,727.35	36,886,299.99	39,671,474.53	43,435,399.16
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense...	194,944.84	15,546.83	1,778,649.68	155,325.85	2,076,698.84	186,362.24
Amortization of Loss on Reacquired Debt..	101,002.97	101,002.98	1,010,029.70	1,009,244.77	1,212,035.66	1,338,646.14
Total..	295,947.81	116,549.81	2,788,679.38	1,164,570.62	3,288,734.50	1,525,008.38
Other Interest Charges						
Customers' Deposits..	114,750.01	136,697.86	1,158,015.04	1,169,143.67	1,377,777.83	1,634,229.55
Other Tax Deficiencies...	-	(28,494.00)	14,000.00	(17,500.00)	14,000.00	(19,527.00)
Interest on DSM Cost Recovery...	1,490.66	4,249.01	12,413.69	23,979.64	14,849.29	29,097.87
Interest on Debt to Associated Companies..	560.07	24,620.75	9,461.72	260,492.66	11,390.94	381,741.93
Other Interest Expense...	148,151.88	33,716.45	976,439.33	728,847.56	1,190,361.94	794,074.81
Total..	264,952.62	170,790.07	2,170,329.78	2,164,963.53	2,608,380.00	2,819,617.16
Total Interest..	$ 3,936,633.01	$ 3,977,567.10	$ 37,621,736.51	$ 40,215,834.14	$ 45,568,589.03	$ 47,780,024.70

November 21, 2011

Louisville Gas and Electric 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..	$ 1,511,141.00	$ 1,227,263.12	$ 15,111,410.00	$ 12,230,744.70
Unemployment..	3,518.97	49,706.42	125,217.16	181,827.10
FICA..	581,702.59	843,198.59	6,521,263.22	6,132,270.66
Public Service Commission Fee..............................	162,886.60	161,096.90	1,618,127.84	1,614,440.14
Federal Income..	2,128,387.52	7,914,704.51	15,978,052.85	32,242,943.36
State Income..	365,732.29	2,876,833.06	8,572,831.36	5,326,411.80
Miscellaneous...	3,246.57	7,222.67	39,823.73	34,579.20
Total Charged to Operating Expense..........	4,756,615.54	13,080,025.27	47,966,726.16	57,763,216.96
Taxes Charged to Other Accounts...........................	300,304.79	5,500,038.98	1,033,183.82	12,372,551.96
Taxes Accrued on Intercompany Accounts.............	-	(226,084.40)	(1,827,411.68)	(2,419,045.05)
Total Taxes Charged..................................	$ 5,056,920.33	$ 18,353,979.85	$ 47,172,498.30	$ 67,716,723.87

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..	$ 11,354,131.66	$ 15,250,085.25	$ 11,553,915.92	$ 15,050,300.99
Unemployment..	54,386.05	88,299.73	142,352.04	333.74
FICA..	590,648.24	5,410,874.60	5,341,905.39	659,617.46
Federal Income..	(3,741,320.05)	14,476,116.40	4,753,055.00	5,981,741.35
State Income..	229,108.93	8,298,921.97	7,288,530.44	1,239,500.46
Kentucky Sales and Use Tax..................................	1,088,857.95	3,532,216.30	4,095,671.81	525,402.44
Miscellaneous...	22,339.97	115,984.05	111,266.02	27,058.00
Totals...	$ 9,598,152.75	$ 47,172,498.30	$ 33,286,696.62	$ 23,483,954.44

November 21, 2011

Louisville Gas and Electric Company
Summary of Utility Plant
October 31, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant In Service**						
Common						
Common General Plant..	$ 159,884,459.36	$ 10,136,576.63	$ (663,361.41)	$ (30,818.06)	$ 9,442,397.16	$ 169,326,856.52
Common Intangible Plant......................................	56,455,326.72	8,621,450.37	(1,661,801.58)	-	6,959,648.79	63,414,975.51
	216,339,786.08	18,758,027.00	(2,325,162.99)	(30,818.06)	16,402,045.95	232,741,832.03
Electric						
Electric Distribution...	927,289,038.50	32,399,496.29	(6,590,514.01)	47,153.43	25,856,135.71	953,145,174.21
Electric General Plant..	16,521,615.59	1,289,339.27	(1,981,092.03)	30,818.06	(660,934.70)	15,860,680.89
Electric Hydro Production.....................................	41,680,209.14	1,085,668.83	(229,943.87)	-	855,724.96	42,535,934.10
Electric Intangible Plant...	2,340.29	-	-	-	-	2,340.29
Electric Other Production......................................	229,401,033.01	2,685,619.00	(981,817.87)	38,429.14	1,742,230.27	231,143,263.28
Electric Steam Production......................................	1,930,347,044.43	202,314,843.39	(23,336,234.85)	3,530,527.24	182,509,135.78	2,112,856,180.21
Electric Transmission...	247,742,496.14	6,674,801.88	(1,230,702.42)	(47,153.43)	5,396,946.03	253,139,442.17
	3,392,983,777.10	246,449,768.66	(34,350,305.05)	3,599,774.44	215,699,238.05	3,608,683,015.15
Gas						
Gas Distribution...	549,799,120.70	40,627,727.32	(606,020.95)	97,729.20	40,119,435.57	589,918,556.27
Gas General Plant..	9,178,093.57	465,366.81	(1,086,872.62)	(97,729.20)	(719,235.01)	8,458,858.56
Gas Intangible Plant...	1,187.49	-	-	-	-	1,187.49
Gas Storage..	78,415,311.06	2,154,059.10	(1,437,514.69)	-	716,544.41	79,131,855.47
Gas Transmission...	16,661,869.68	970,087.61	(20,299.95)	3,941,518.65	4,891,306.31	21,553,175.99
	654,055,582.50	44,217,240.84	(3,150,708.21)	3,941,518.65	45,008,051.28	699,063,633.78
Total 101 Accounts..................................	4,263,379,145.68	309,425,036.50	(39,826,176.25)	7,510,475.03	277,109,335.28	4,540,488,480.96
105 **Plant Held For Future Use**						
Electric						
Electric Distribution...	649,014.48	-	-	-	-	649,014.48
Electric Steam Production......................................	4,182,559.70	-	-	(4,182,559.70)	(4,182,559.70)	-
	4,831,574.18	-	-	(4,182,559.70)	(4,182,559.70)	649,014.48
Total 105001...	$ 4,831,574.18	$ -	$ -	$ (4,182,559.70)	$ (4,182,559.70)	$ 649,014.48

November 21, 2011

Louisville Gas and Electric Company
Summary of Utility Plant
October 31, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
106 **Completed Construction Not Classified**						
Common						
Common General Plant	$ 597,158.63	$ 1,022,595.22	$ -	$ -	$ 1,022,595.22	$ 1,619,753.85
Common Intangible Plant	2,714,931.36	(904,675.53)	-	-	(904,675.53)	1,810,255.83
	3,312,089.99	117,919.69	-	-	117,919.69	3,430,009.68
Electric						
Electric Distribution	11,544,733.90	10,053,606.33	-	-	10,053,606.33	21,598,340.23
Electric General Plant	50,763.87	(50,763.87)	-	-	(50,763.87)	-
Electric Hydro Production	16,952.26	(495.90)	-	-	(495.90)	16,456.36
Electric Intangible Plant	-	-	-	-	-	-
Electric Other Production	1,767,208.21	(247,230.79)	-	-	(247,230.79)	1,519,977.42
Electric Steam Production	15,929,229.77	9,543,051.95	-	-	9,543,051.95	25,472,281.72
Electric Transmission	35,045,472.82	744,940.00	-	-	744,940.00	35,790,412.82
	64,354,360.83	20,043,107.72	-	-	20,043,107.72	84,397,468.55
Gas						
Gas Distribution	24,420,156.16	(7,847,164.83)	-	-	(7,847,164.83)	16,572,991.33
Gas General Plant	126,992.17	93,185.49	-	-	93,185.49	220,177.66
Gas Intangible Plant	-	-	-	-	-	-
Gas Storage	951,426.06	488,465.58	-	-	488,465.58	1,439,891.64
Gas Transmission	-	1,294,872.51	-	-	1,294,872.51	1,294,872.51
	25,498,574.39	(5,970,641.25)	-	-	(5,970,641.25)	19,527,933.14
Total 106 Accounts	93,165,025.21	14,190,386.16	-	-	14,190,386.16	107,355,411.37
117 **Gas Stored Underground-Noncurrent**						
Gas						
Gas Stored Nonrecoverable	2,139,990.00	-	-	-	-	2,139,990.00
	2,139,990.00	-	-	-	-	2,139,990.00
Total 117001	2,139,990.00	-	-	-	-	2,139,990.00
121 **Nonutility Property**						
Common						
Non Utility Property	75,239.56	-	-	-	-	75,239.56
	75,239.56	-	-	-	-	75,239.56
Total 121001	75,239.56	-	-	-	-	75,239.56
107 **Construction Work In Progress**						
Common	21,243,879.89	(10,749,951.71)	-	-	(10,749,951.71)	10,493,928.18
Electric	324,323,732.14	(170,377,972.35)	-	-	(170,377,972.35)	153,945,759.79
Gas	39,756,306.91	(741,578.96)	-	-	(741,578.96)	39,014,727.95
	385,323,918.94	(181,869,503.02)	-	-	(181,869,503.02)	203,454,415.92
Total Plant (Non-CWIP)	4,363,590,974.63	323,615,422.66	(39,826,176.25)	3,327,915.33	287,117,161.74	4,650,708,136.37
Total Plant + CWIP	4,748,914,893.57	141,745,919.64	(39,826,176.25)	3,327,915.33	105,247,658.72	4,854,162,552.29
Total Plant + CWIP - Non Utility	$ 4,748,839,654.01	$ 141,745,919.64	$ (39,826,176.25)	$ 3,327,915.33	$ 105,247,658.72	$ 4,854,087,312.73

November 21, 2011

Louisville Gas and Electric 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										
Common General Plant	$ (77,263,235.10)	$ (10,705,793.77)	$ 663,361.41	$ 30,818.06	$ -	$ -	$ -	$ -	$ -	$ (87,274,849.40)
Common General Plant - ARO	(343.19)	(1,717.00)	-	-	-	-	-	-	-	(2,060.19)
Electric Distribution	(277,000,365.75)	(14,476,987.10)	6,590,514.01	(382.60)	-	-	-	-	-	(284,887,221.44)
Electric Distribution - ARO	(1,256.54)	(5,028.21)	-	-	-	-	-	-	-	(6,284.75)
Electric General Plant	(12,910,034.19)	(350,205.10)	1,981,092.03	(30,818.06)	-	-	-	-	-	(11,309,965.32)
Electric Hydro Production	(9,718,276.66)	(469,351.69)	229,943.87	-	-	-	-	-	-	(9,957,684.48)
Electric Hydro Production - ARO	(364.10)	(1,457.10)	-	-	-	-	-	-	-	(1,821.20)
Electric Other Production	(60,282,055.17)	(6,821,738.49)	981,817.87	-	-	-	-	-	-	(66,121,975.79)
Electric Other Production - ARO	(192.68)	(917.02)	-	-	-	-	-	-	-	(1,109.70)
Electric Steam Production	(1,029,518,070.37)	(47,323,988.33)	22,604,029.81	-	-	-	-	-	-	(1,054,238,028.89)
Electric Steam Production - ARO	(204,061.94)	(1,771,779.76)	732,205.04	116,513.06	-	-	-	-	-	(1,127,123.60)
Electric Transmission	(119,192,606.75)	(3,655,380.46)	1,230,702.42	382.60	-	-	-	-	-	(121,616,902.19)
Electric Transmission - ARO	(41.40)	(165.70)	-	-	-	-	-	-	-	(207.10)
Gas Distribution	(125,049,477.23)	(9,637,277.10)	530,981.68	(13,332.40)	-	-	-	-	-	(134,169,105.05)
Gas Distribution - ARO	(49,734.93)	(322,129.95)	75,039.27	-	-	-	-	-	-	(296,825.61)
Gas General Plant	(6,299,629.20)	(265,827.85)	1,086,872.62	13,332.40	-	-	-	-	-	(5,465,252.03)
Gas Storage	(31,288,281.49)	(902,040.85)	1,042,109.23	-	-	-	-	-	-	(31,148,213.11)
Gas Storage - ARO	(39,466.10)	(576,793.67)	395,405.46	-	-	-	-	-	-	(220,854.31)
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(9,448,605.32)	(47,929.19)	20,299.95	-	-	-	-	-	-	(9,476,234.56)
Gas Transmission - ARO		(17,635.44)								(17,635.44)
Non Utility Property	(63,360.36)	-	-	-	-	-	-	-	-	(63,360.36)
	(1,758,329,458.47)	(97,354,143.78)	38,164,374.67	116,513.06	-	-	-	-	-	(1,817,402,714.52)
Cost Of Removal										
Common General Plant	(688,372.47)	(234,354.57)	-	-	-	-	332,962.76	-	-	(589,764.28)
Electric Distribution	(146,715,298.78)	(5,734,630.89)	-	(55.48)	-	-	3,719,176.23	-	-	(148,730,808.92)
Electric General Plant	3,866.64	-	-	-	-	-	-	-	-	3,866.64
Electric Hydro Production	736,907.70	(35,645.29)	-	-	-	-	38,351.42	-	-	739,613.83
Electric Other Production	(2,505,175.99)	(292,671.83)	-	-	-	-	123,730.22	-	-	(2,674,117.60)
Electric Steam Production	(94,783,295.15)	(14,152,641.20)	-	-	-	-	2,962,485.74	-	-	(105,973,450.61)
Electric Transmission	(24,538,454.78)	(1,176,388.52)	-	55.48	-	-	134,289.80	-	-	(25,580,498.02)
Gas Distribution	(60,212,131.14)	(2,724,362.07)	-	-	-	-	1,487,211.13	-	-	(61,449,282.08)
Gas General Plant	(0.02)	-	-	-	-	-	-	-	-	(0.02)
Gas Storage	(170,437.90)	(117,044.76)	-	-	-	-	565,052.30	-	-	277,569.64
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(3,016,813.95)	(11,858.18)	-	-	-	-	46,319.99	-	-	(2,982,352.14)
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	$ (331,889,205.84)	$ (24,479,597.31)	$ -	$ -	$ -	$ -	$ 9,409,579.59	$ -	$ -	$ (346,959,223.56)

November 21, 2011

Louisville Gas and Electric 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
Salvage										
Common General Plant	$ 278,074.55	$ 319.40	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 278,393.95
Electric Distribution	17,535,024.98	1,162,298.48	-	-	-	-	-	(197,553.22)	-	18,499,770.24
Electric General Plant	138,281.25	1,925.50	-	-	-	-	-	-	-	140,206.75
Electric Hydro Production	376,638.17	-	-	-	-	-	-	-	-	376,638.17
Electric Other Production	(18,998.67)	-	-	-	-	-	-	-	-	(18,998.67)
Electric Steam Production	22,028,570.14	1,686,508.42	-	-	-	-	-	(34,636.38)	-	23,680,442.18
Electric Transmission	6,247,368.67	218,103.15	-	-	-	-	-	-	-	6,465,471.82
Gas Distribution	3,594,440.75	166,190.27	-	-	-	-	-	-	-	3,760,631.02
Gas General Plant	225,788.37	1,913.55	-	-	-	-	-	-	-	227,701.92
Gas Storage	269,933.04	14,318.91	-	-	-	-	-	-	-	284,251.95
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	217,923.11	4,446.81	-	-	-	-	-	-	-	222,369.92
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	50,893,044.36	3,256,024.49	-	-	-	-	-	(232,189.60)	-	53,916,879.25
Total Reserves										
Common	(77,737,236.57)	(10,941,545.94)	663,361.41	30,818.06	-	-	332,962.76	-	-	(87,651,640.28)
Electric	(1,730,321,891.37)	(93,200,141.14)	34,350,305.05	85,695.00	-	-	6,978,033.41	(232,189.60)	-	(1,782,340,188.65)
Gas	(231,266,492.01)	(14,436,029.52)	3,150,708.21	0.00	-	-	2,098,583.42	-	-	(240,453,229.90)
	(2,039,325,619.95)	(118,577,716.60)	38,164,374.67	116,513.06	-	-	9,409,579.59	(232,189.60)	-	(2,110,445,058.83)
Retirement Work In Progress										
Common	342,947.00	-	-	162,020.85	-	(332,962.76)	18,615.75	(20,894.00)	2,144.92	171,871.76
Electric	9,603,653.21	-	-	(78,968.13)	(1,142,636.19)	(6,171,452.86)	9,004,346.34	(470,495.74)	(336,973.02)	10,407,473.61
Gas	2,523,160.64	-	-	(23,759.86)	(1,053,809.06)	(1,302,779.70)	1,191,624.17	(6,508.40)	(2,703.32)	1,325,224.47
	12,469,760.85	-	-	59,292.86	(2,196,445.25)	(7,807,195.32)	10,214,586.26	(497,898.14)	(337,531.42)	11,904,569.84
YTD ACTIVITY	(2,026,855,859.10)	(118,577,716.60)	38,164,374.67	175,805.92	(2,196,445.25)	(7,807,195.32)	19,624,165.85	(730,087.74)	(337,531.42)	(2,098,540,488.99)
Amortization										
Common	(16,306,390.60)	(6,716,656.59)	1,661,801.58	-	-	-	-	-	-	(21,361,245.61)
Electric	(100.00)	-	-	-	-	-	-	-	-	(100.00)
Gas	(800.00)	-	-	-	-	-	-	-	-	(800.00)
AMORTIZATION TOTAL	(16,307,290.60)	(6,716,656.59)	1,661,801.58	-	-	-	-	-	-	(21,362,145.61)
Depreciation & Amortization Total	$ (2,043,163,149.70)	$ (125,294,373.19)	$ 39,826,176.25	$ 175,805.92	$ (2,196,445.25)	$ (7,807,195.32)	$ 19,624,165.85	$ (730,087.74)	$ (337,531.42)	$ (2,119,902,634.60)
Depr & Amort - Nonutility for Balance Sheet										(2,119,839,274.24)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)	$ 2,705,739,864.67									$ 2,734,248,038.49

November 21, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
October 31, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 79,332,461.18	$ -	$ 79,332,461.18
Gas Operating Revenues	18,830,221.33	-	18,830,221.33
Total Operating Revenues	98,162,682.51	-	98,162,682.51
Fuel for Electric Generation	26,589,929.51	-	26,589,929.51
Power Purchased	7,628,086.41	-	7,628,086.41
Gas Supply Expenses	9,674,278.22	-	9,674,278.22
Other Operation Expenses	19,563,220.37	-	19,563,220.37
Maintenance	10,777,128.87	-	10,777,128.87
Depreciation	11,928,154.12	-	11,928,154.12
Amortization Expense	705,150.17	-	705,150.17
Regulatory Credits	(468,815.78)	-	(468,815.78)
Taxes			
Federal Income	2,128,387.52	-	2,128,387.52
State Income	365,732.29	-	365,732.29
Deferred Federal Income - Net	317,260.52	8,230.80	325,491.32
Deferred State Income - Net	(182,282.46)	1,501.06	(180,781.40)
Property and Other	2,262,495.73	-	2,262,495.73
Amortization of Investment Tax Credit	(236,034.00)	-	(236,034.00)
Loss (Gain) from Disposition of Allowances	-	-	-
Accretion Expense	230,794.03	-	230,794.03
Total Operating Expenses	91,283,485.52	9,731.86	91,293,217.38
Net Operating Income	6,879,196.99	(9,731.86)	6,869,465.13
Other Income Less Deductions	(6,213.08)	-	(6,213.08)
Income Before Interest Charges	6,872,983.91	(9,731.86)	6,863,252.05
Interest on Long-Term Debt	3,375,732.58	(25,017.63)	3,350,714.95
Amortization of Debt Expense - Net	295,947.81	-	295,947.81
Other Interest Expenses	264,952.62	-	264,952.62
Total Interest Charges	3,936,633.01	(25,017.63)	3,911,615.38
Net Income	$ 2,936,350.90	$ 15,285.77	$ 2,951,636.67

Note: Purchase accounting is subject to change through October 31, 2011

November 21, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
October 31, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues..	$ 895,157,751.99	$ -	$ 895,157,751.99
Gas Operating Revenues..	236,825,715.41	-	236,825,715.41
Total Operating Revenues...	1,131,983,467.40	-	1,131,983,467.40
Fuel for Electric Generation...	300,385,048.56	-	300,385,048.56
Power Purchased..	62,889,505.23	-	62,889,505.23
Gas Supply Expenses...	126,547,876.24	-	126,547,876.24
Other Operation Expenses...	197,023,845.01	27,884.66	197,051,729.67
Maintenance..	96,605,185.36	-	96,605,185.36
Depreciation..	118,219,543.76	-	118,219,543.76
Amortization Expense..	6,716,656.59	-	6,716,656.59
Regulatory Credits...	(4,879,692.31)	-	(4,879,692.31)
Taxes			
Federal Income..	15,978,052.85	-	15,978,052.85
State Income...	8,572,831.36	-	8,572,831.36
Deferred Federal Income - Net..................................	38,590,406.90	73,195.75	38,663,602.65
Deferred State Income - Net.....................................	(135,871.40)	13,348.78	(122,522.62)
Property and Other..	23,415,841.96	-	23,415,841.96
Amortization of Investment Tax Credit.....................	(2,333,673.00)	-	(2,333,673.00)
Loss (Gain) from Disposition of Allowances................	(2,577.94)	-	(2,577.94)
Accretion Expense...	2,182,068.46	-	2,182,068.46
Total Operating Expenses...	989,775,047.63	114,429.19	989,889,476.82
Net Operating Income..	142,208,419.77	(114,429.19)	142,093,990.58
Other Income Less Deductions.................................	532,247.85	-	532,247.85
Income Before Interest Charges................................	142,740,667.62	(114,429.19)	142,626,238.43
Interest on Long-Term Debt...	32,662,727.35	(250,176.30)	32,412,551.05
Amortization of Debt Expense - Net............................	2,788,679.38	-	2,788,679.38
Other Interest Expenses...	2,170,329.78	-	2,170,329.78
Total Interest Charges...	37,621,736.51	(250,176.30)	37,371,560.21
Net Income..	$ 105,118,931.11	$ 135,747.11	$ 105,254,678.22

Note: Purchase accounting is subject to change through October 31, 2011

November 21, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
October 31, 2011

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period…………………………….	$ 874,925,832.17	$ 807,159,675.10	$ (808,778,821.10)	$ -	$ 66,147,011.07	$ 807,159,675.10
Add:						
Net Income (Loss) for Period…………………………	2,936,350.90	1,787,216.42	15,285.77	-	2,951,636.67	1,787,216.42
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	-	-	-	-	-	-
Balance at End of Period………………………………….	$ 877,862,183.07	$ 808,946,891.52	$ (808,763,535.33)	$ -	$ 69,098,647.74	$ 808,946,891.52

Note: Purchase accounting is subject to change through October 31, 2011

November 21, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
October 31, 2011

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period…………………………….	$ 827,993,251.96	$ 755,278,866.24	$ (808,899,282.44)	$ -	$ 19,093,969.52	$ 755,278,866.24
Add:						
Net Income (Loss) for Period………………………….	105,118,931.11	108,668,025.28	135,747.11	-	105,254,678.22	108,668,025.28
Deduct:						
Adjustment to Retained Earnings…………………….	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	55,250,000.00	55,000,000.00	-	-	55,250,000.00	55,000,000.00
Balance at End of Period……………………………………	$ 877,862,183.07	$ 808,946,891.52	$ (808,763,535.33)	$ -	$ 69,098,647.74	$ 808,946,891.52

Note: Purchase accounting is subject to change through October 31, 2011

November 21, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
October 31, 2011

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……………………………	$ 808,946,891.52	$ 741,251,623.67	$ -	$ -	$ 808,946,891.52	$ 741,251,623.67
Add:						
Net Income (Loss) for Period…………………………	124,165,291.55	122,695,267.85	183,356.19	-	124,348,647.74	122,695,267.85
Deduct:						
Adjustment to Retained Earnings……………………	-	-	808,946,891.52	-	808,946,891.52	-
Common Dividends						
Common Stock Without Par Value………………	55,250,000.00	55,000,000.00	-	-	55,250,000.00	55,000,000.00
Balance at End of Period…………………………………	$ 877,862,183.07	$ 808,946,891.52	$ (808,763,535.33)	$ -	$ 69,098,647.74	$ 808,946,891.52

Note: Purchase accounting is subject to change through October 31, 2011

November 21, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of October 31, 2011

Assets	Without Purchase Accounting	Purchase Accounting	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 4,854,087,312.73	$ -	$ 4,854,087,312.73
Less: Reserves for Depreciation and Amortization....	2,119,839,274.24	-	2,119,839,274.24
Total..	2,734,248,038.49	-	2,734,248,038.49
Investments			
Ohio Valley Electric Corporation.............................	594,286.00	-	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	-	11,879.20
Special Funds...	29,513,085.39	-	29,513,085.39
Total..	30,119,250.59	-	30,119,250.59
Current and Accrued Assets			
Cash..	42,810,271.73	-	42,810,271.73
Special Deposits..	557,339.76	-	557,339.76
Temporary Cash Investments...................................	31,125,914.89	-	31,125,914.89
Accounts Receivable - Less Reserve........................	105,912,233.14	-	105,912,233.14
Accounts Receivable from Associated Companies....	11,234,858.52	-	11,234,858.52
Materials and Supplies - At Average Cost			
Fuel..	59,220,758.36	-	59,220,758.36
Plant Materials and Operating Supplies.................	30,813,805.38	-	30,813,805.38
Stores Expense...	5,577,590.22	-	5,577,590.22
Gas Stored Underground.......................................	66,152,494.75	-	66,152,494.75
Emission Allowances...	24,614.20	-	24,614.20
Prepayments..	5,460,672.11	-	5,460,672.11
Miscellaneous Current and Accrued Assets..............	607,780.56	-	607,780.56
Total..	359,498,333.62	-	359,498,333.62
Deferred Debits and Other			
Unamortized Debt Expense......................................	13,557,379.65	(3,512,274.27)	10,045,105.38
Unamortized Loss on Bonds....................................	20,924,619.95	-	20,924,619.95
Accumulated Deferred Income Taxes.......................	26,434,331.06	72,399,448.49	98,833,779.55
Deferred Regulatory Assets.....................................	376,302,783.78	9,785,850.40	386,088,634.18
Other Deferred Debits..	1,365,988.12	168,952,547.95	170,318,536.07
Goodwill..	-	389,157,351.59	389,157,351.59
Total..	438,585,102.56	636,782,924.16	1,075,368,026.72
Total Assets..	$ 3,562,450,725.26	$ 636,782,924.16	$ 4,199,233,649.42

Note: Purchase accounting is subject to change through October 31, 2011

November 21, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of October 31, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting	Total
Proprietary Capital			
Common Stock......	$ 425,170,424.09	$ -	$ 425,170,424.09
Less: Common Stock Expense......	835,888.64	-	835,888.64
Paid-In Capital......	83,581,499.00	1,194,085,869.02	1,277,667,368.02
Other Comprehensive Income......	-	-	-
Retained Earnings......	877,862,183.07	(808,763,535.33)	69,098,647.74
Total Proprietary Capital......	1,385,778,217.52	385,322,333.69	1,771,100,551.21
Pollution Control Bonds - Net of Reacquired Bonds....	574,304,000.00	6,276,505.44	580,580,505.44
First Mortgage Bonds......	531,284,899.12	-	531,284,899.12
LT Notes Payable to Associated Companies......	-	-	-
Total Long-Term Debt......	1,105,588,899.12	6,276,505.44	1,111,865,404.56
Total Capitalization......	2,491,367,116.64	391,598,839.13	2,882,965,955.77
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies......	-	-	-
Accounts Payable......	91,057,684.20	-	91,057,684.20
Accounts Payable to Associated Companies......	13,798,613.52	-	13,798,613.52
Customer Deposits......	22,425,873.82	-	22,425,873.82
Taxes Accrued......	23,483,954.44	-	23,483,954.44
Dividends Declared......	-	-	-
Interest Accrued......	13,345,579.80	-	13,345,579.80
Miscellaneous Current and Accrued Liabilities......	19,943,526.53	-	19,943,526.53
Total......	184,055,232.31	-	184,055,232.31
Deferred Credits and Other			
Accumulated Deferred Income Taxes......	487,243,920.69	69,957,960.95	557,201,881.64
Investment Tax Credit......	43,190,903.13	-	43,190,903.13
Regulatory Liabilities......	61,440,578.69	168,952,547.95	230,393,126.64
Customer Advances for Construction......	8,022,178.51	-	8,022,178.51
Asset Retirement Obligations......	55,792,039.70	-	55,792,039.70
Other Deferred Credits......	32,850,657.34	6,273,576.13	39,124,233.47
Miscellaneous Long-Term Liabilities......	54,212,429.21	-	54,212,429.21
Misc Long-Term Liab Due to Assoc Cos......	-	-	-
Accum Provision for Postretirement Benefits......	144,275,669.04	-	144,275,669.04
Total......	887,028,376.31	245,184,085.03	1,132,212,461.34
Total Liabilities and Stockholders' Equity......	$ 3,562,450,725.26	$ 636,782,924.16	$ 4,199,233,649.42

Note: Purchase accounting is subject to change through October 31, 2011

November 21, 2011

LOUISVILLE GAS AND ELECTRIC COMPANY

Financial Reports

September 30, 2011

Index
Financial and Operating Reports

Louisville Gas and Electric 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.

Louisville Gas and Electric Company
Comparative Statement of Income
September 30, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 86,259,338.17	$ 78,289,808.76	$ 7,969,529.41	10.18
Gas Operating Revenues...	12,116,422.24	11,720,038.06	396,384.18	3.38
Total Operating Revenues...	98,375,760.41	90,009,846.82	8,365,913.59	9.29
Fuel for Electric Generation...	30,046,419.94	32,175,696.63	(2,129,276.69)	(6.62)
Power Purchased..	5,507,089.89	3,567,377.67	1,939,712.22	54.37
Gas Supply Expenses..	4,361,801.03	4,275,545.62	86,255.41	2.02
Other Operation Expenses..	18,985,899.75	20,487,061.23	(1,501,161.48)	(7.33)
Maintenance..	3,499,646.07	7,874,582.26	(4,374,936.19)	(55.56)
Depreciation..	11,821,283.70	11,352,742.53	468,541.17	4.13
Amortization Expense...	691,375.44	622,759.42	68,616.02	11.02
Regulatory Credits..	(367,360.47)	(1,813,934.34)	1,446,573.87	79.75
Taxes				
Federal Income..	(3,676,576.81)	(6,683,028.40)	3,006,451.59	44.99
State Income...	(167,428.46)	(1,354,225.08)	1,186,796.62	87.64
Deferred Federal Income - Net.................................	8,906,276.75	7,130,807.58	1,775,469.17	24.90
Deferred State Income - Net......................................	893,120.86	1,489,773.74	(596,652.88)	(40.05)
Property and Other..	2,790,700.09	1,940,595.20	850,104.89	43.81
Investment Tax Credit...	-	-	-	-
Amortization of Investment Tax Credit.....................	(236,034.00)	(208,481.00)	(27,553.00)	(13.22)
Loss (Gain) from Disposition of Allowances...............	-	-	-	-
Accretion Expense..	202,763.84	1,334,111.60	(1,131,347.76)	(84.80)
Total Operating Expenses...	83,258,977.62	82,191,384.66	1,067,592.96	1.30
Net Operating Income..	15,116,782.79	7,818,462.16	7,298,320.63	93.35
Other Income Less Deductions.................................	153,501.78	17,112,550.25	(16,959,048.47)	(99.10)
Income Before Interest Charges................................	15,270,284.57	24,931,012.41	(9,660,727.84)	(38.75)
Interest on Long-Term Debt...	3,255,663.30	3,263,942.70	(8,279.40)	(0.25)
Amortization of Debt Expense - Net............................	280,500.88	116,549.81	163,951.07	140.67
Other Interest Expenses..	238,238.63	263,856.54	(25,617.91)	(9.71)
Total Interest Charges...	3,774,402.81	3,644,349.05	130,053.76	3.57
Net Income..	$ 11,495,881.76	$ 21,286,663.36	$ (9,790,781.60)	(45.99)

October 26, 2011

Louisville Gas and Electric Company
Comparative Statement of Income
September 30, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 815,825,290.81	$ 775,492,907.17	$ 40,332,383.64	5.20
Gas Operating Revenues...	217,995,494.08	201,229,558.27	16,765,935.81	8.33
Total Operating Revenues...	1,033,820,784.89	976,722,465.44	57,098,319.45	5.85
Fuel for Electric Generation...	273,795,119.05	277,395,215.56	(3,600,096.51)	(1.30)
Power Purchased..	55,261,418.82	40,858,584.94	14,402,833.88	35.25
Gas Supply Expenses..	116,873,598.02	108,041,714.88	8,831,883.14	8.17
Other Operation Expenses...	177,460,624.64	168,104,479.46	9,356,145.18	5.57
Maintenance..	85,828,056.49	76,857,618.20	8,970,438.29	11.67
Depreciation..	106,291,389.64	98,439,672.75	7,851,716.89	7.98
Amortization Expense...	6,011,506.42	5,835,257.86	176,248.56	3.02
Regulatory Credits..	(4,410,876.53)	(3,270,841.78)	(1,140,034.75)	(34.85)
Taxes				
Federal Income..	13,849,665.33	24,328,238.85	(10,478,573.52)	(43.07)
State Income...	8,207,099.07	2,449,578.74	5,757,520.33	235.04
Deferred Federal Income - Net.................................	38,273,146.38	22,314,183.39	15,958,962.99	71.52
Deferred State Income - Net......................................	46,411.06	5,911,911.87	(5,865,500.81)	(99.22)
Property and Other...	21,153,346.23	17,905,374.10	3,247,972.13	18.14
Investment Tax Credit..	-	-	-	-
Amortization of Investment Tax Credit.....................	(2,097,639.00)	(1,876,331.00)	(221,308.00)	(11.79)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	1,951,274.43	2,673,901.02	(722,626.59)	(27.03)
Total Operating Expenses...	898,491,562.11	845,934,098.70	52,557,463.41	6.21
Net Operating Income..	135,329,222.78	130,788,366.74	4,540,856.04	3.47
Other Income Less Deductions.................................	538,460.93	12,330,709.16	(11,792,248.23)	(95.63)
Income Before Interest Charges................................	135,867,683.71	143,119,075.90	(7,251,392.19)	(5.07)
Interest on Long-Term Debt...	29,286,994.77	33,196,072.77	(3,909,078.00)	(11.78)
Amortization of Debt Expense - Net............................	2,492,731.57	1,048,020.81	1,444,710.76	137.85
Other Interest Expenses..	1,905,377.16	1,994,173.46	(88,796.30)	(4.45)
Total Interest Charges...	33,685,103.50	36,238,267.04	(2,553,163.54)	(7.05)
Net Income..	$ 102,182,580.21	$ 106,880,808.86	$ (4,698,228.65)	(4.40)

October 26, 2011

Louisville Gas and Electric 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..	$ 1,055,943,950.61	$ 982,532,571.27	$ 73,411,379.34	7.47
Gas Operating Revenues...	319,713,291.69	286,927,629.17	32,785,662.52	11.43
Total Operating Revenues...	1,375,657,242.30	1,269,460,200.44	106,197,041.86	8.37
Fuel for Electric Generation...	364,956,229.83	349,089,411.17	15,866,818.66	4.55
Power Purchased..	68,782,552.57	56,239,440.77	12,543,111.80	22.30
Gas Supply Expenses...	177,835,491.19	163,529,115.26	14,306,375.93	8.75
Other Operation Expenses..	236,169,149.75	221,327,220.67	14,841,929.08	6.71
Maintenance..	120,671,543.37	106,467,709.93	14,203,833.44	13.34
Depreciation..	139,061,720.16	130,979,831.16	8,081,889.00	6.17
Amortization Expense...	7,903,237.46	7,945,238.96	(42,001.50)	(0.53)
Regulatory Credits..	(5,409,766.20)	(3,809,874.69)	(1,599,891.51)	(41.99)
Taxes				
Federal Income..	18,396,033.66	41,499,726.50	(23,103,692.84)	(55.67)
State Income..	11,804,687.76	3,769,525.84	8,035,161.92	213.16
Deferred Federal Income - Net.................................	43,625,967.99	(2,512,278.36)	46,138,246.35	1,836.51
Deferred State Income - Net......................................	(3,495,476.37)	3,485,692.43	(6,981,168.80)	(200.28)
Property and Other..	25,819,595.95	21,414,725.16	4,404,870.79	20.57
Investment Tax Credit...	-	1,055,156.02	(1,055,156.02)	(100.00)
Amortization of Investment Tax Credit.....................	(2,723,082.00)	(2,627,838.72)	(95,243.28)	(3.62)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	2,561,479.04	3,164,629.08	(603,150.04)	(19.06)
Total Operating Expenses...	1,205,956,786.22	1,100,982,971.04	104,973,815.18	9.53
Net Operating Income..	169,700,456.08	168,477,229.40	1,223,226.68	0.73
Other Income Less Deductions.................................	(1,074,775.89)	5,236,330.25	(6,311,106.14)	(120.53)
Income Before Interest Charges................................	168,625,680.19	173,713,559.65	(5,087,879.46)	(2.93)
Interest on Long-Term Debt...	39,985,969.17	43,661,411.53	(3,675,442.36)	(8.42)
Amortization of Debt Expense - Net............................	3,109,336.50	1,396,888.51	1,712,447.99	122.59
Other Interest Expenses..	2,514,217.45	2,761,994.19	(247,776.74)	(8.97)
Total Interest Charges...	45,609,523.12	47,820,294.23	(2,210,771.11)	(4.62)
Net Income..	$ 123,016,157.07	$ 125,893,265.42	$ (2,877,108.35)	(2.29)

October 26, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings
September 30, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period..	$ 863,429,950.41	$ 810,873,011.74	$ 827,993,251.96	$ 755,278,866.24	$ 807,159,675.10	$ 736,266,409.68
Add:						
Net Income for Period..	11,495,881.76	21,286,663.36	102,182,580.21	106,880,808.86	123,016,157.07	125,893,265.42
Deduct:						
Common Dividends						
Common Stock Without Par Value.....................	-	25,000,000.00	55,250,000.00	55,000,000.00	55,250,000.00	55,000,000.00
Balance at End of Period..	$ 874,925,832.17	$ 807,159,675.10	$ 874,925,832.17	$ 807,159,675.10	$ 874,925,832.17	$ 807,159,675.10

October 26, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of September 30, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,834,755,063.44	$ 4,644,050,008.98
Less: Reserves for Depreciation and Amortization	2,109,448,034.24	2,023,632,803.62
Total	2,725,307,029.20	2,620,417,205.36
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	29,511,083.19	21,152,872.82
Total	30,117,248.39	21,759,038.02
Current and Accrued Assets		
Cash	36,121,124.88	3,904,029.96
Special Deposits	1,203,174.45	694,666.13
Temporary Cash Investments	38,421,281.63	119.71
Accounts Receivable - Less Reserve	115,617,416.71	131,282,221.86
Accounts Receivable from Associated Companies	10,903,711.10	16,943,535.45
Materials and Supplies - At Average Cost		
Fuel	52,528,086.41	65,769,984.00
Plant Materials and Operating Supplies	30,797,037.86	29,786,478.70
Stores Expense	5,476,575.61	4,860,767.32
Gas Stored Underground	56,853,462.78	60,652,456.09
Emission Allowances	2,772.88	3,007.09
Prepayments	6,339,120.25	4,911,746.03
Miscellaneous Current and Accrued Assets	761,979.55	1,807,657.91
Total	355,025,744.11	320,616,670.25
Deferred Debits and Other		
Unamortized Debt Expense	13,044,553.50	3,714,382.80
Unamortized Loss on Bonds	21,025,622.90	22,237,658.30
Accumulated Deferred Income Taxes	26,152,975.69	46,431,887.66
Deferred Regulatory Assets	383,199,682.64	378,525,174.50
Other Deferred Debits	1,330,450.74	1,197,806.18
Total	444,753,285.47	452,106,909.44
Total Assets	$ 3,555,203,307.17	$ 3,414,899,823.07

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	874,925,832.17	807,159,675.10
Total Proprietary Capital	1,382,841,866.62	1,315,075,709.55
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	411,104,000.00
First Mortgage Bonds	531,261,577.46	-
LT Notes Payable to Associated Companies	-	485,000,000.00
Total Long-Term Debt	1,105,565,577.46	896,104,000.00
Total Capitalization	2,488,407,444.08	2,211,179,709.55
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	121,885,400.00
Accounts Payable	81,366,680.34	83,374,445.21
Accounts Payable to Associated Companies	21,152,123.73	38,853,764.01
Customer Deposits	22,546,494.46	24,435,083.96
Taxes Accrued	18,953,407.93	20,358,882.40
Interest Accrued	12,029,932.24	3,555,639.55
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	21,917,601.45	20,902,601.42
Total	177,966,240.15	313,365,816.55
Deferred Credits and Other		
Accumulated Deferred Income Taxes	487,104,353.22	459,200,169.51
Investment Tax Credit	43,426,937.13	46,150,019.13
Regulatory Liabilities	60,890,790.21	51,562,025.10
Customer Advances for Construction	8,049,779.58	8,229,472.91
Asset Retirement Obligations	55,794,013.83	64,974,252.91
Other Deferred Credits	29,396,986.25	28,608,492.59
Miscellaneous Long-Term Liabilities	58,630,593.68	54,476,525.20
Accum Provision for Postretirement Benefits	145,536,169.04	177,153,339.62
Total	888,829,622.94	890,354,296.97
Total Liabilities and Stockholders' Equity	$ 3,555,203,307.17	$ 3,414,899,823.07

October 26, 2011

Louisville Gas and Electric 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..	75,000,000	21,294,223	$ 425,170,424.09	
Less: Common Stock Expense..			835,888.64	
Paid-In Capital..			83,581,499.00	
Other Comprehensive Income..			-	
Retained Earnings...			874,925,832.17	
Total Proprietary Capital..			1,382,841,866.62	55.57
Long-Term Debt				
Pollution Control Bonds...				
Jefferson County 2000 Series A due 05/01/27 5.375%.................			25,000,000.00	
Trimble County 2000 Series A due 08/01/30 Var%......................			83,335,000.00	
Jefferson County 2001 Series A due 09/01/26 Var%...................			22,500,000.00	
Jefferson County 2001 Series A due 09/01/27 Var%....................			10,104,000.00	
Jefferson County 2001 Series B due 11/01/27 Var%...................			35,000,000.00	
Trimble County 2001 Series A due 09/01/26 Var%......................			27,500,000.00	
Trimble County 2001 Series A due 10/01/32 Var%......................			41,665,000.00	
Trimble County 2001 Series B due 11/01/27 Var%......................			35,000,000.00	
Louisville Metro 2003 Series A due 10/01/33 1.900%..................			128,000,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%..................			40,000,000.00	
Louisville Metro 2007 Series A due 06/01/33 5.625%..................			31,000,000.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%..................			35,200,000.00	
Trimble County 2007 Series A due 06/01/33 4.600%...................			60,000,000.00	
Total Pollution Control Bonds..			574,304,000.00	23.08
First Mortgage Bonds...				
First Mortgage Bond Due 11/15/15 1.625%..................................			250,000,000.00	
First Mortgage Bond Due 11/15/40 5.125%..................................			285,000,000.00	
Total First Mortgage Bonds..			535,000,000.00	21.50
Less: First Mortgage Bonds Debt Discount......................................				
First Mortgage Bond Due 11/15/15 1.625%..................................			(728,062.52)	
First Mortgage Bond Due 11/15/40 5.125%..................................			(3,010,360.02)	
			(3,738,422.54)	-0.15
Total First Mortgage Bonds - Net of Debt Discount.........................			531,261,577.46	21.35
Total Capitalization..			$ 2,488,407,444.08	100.00

October 26, 2011

Louisville Gas and Electric Company
Summary Trial Balance
September 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 4,834,755,063.44	$ 4,834,755,063.44
Reserves for Depreciation and Amortization		(2,109,448,034.24)
Depreciation of Plant		
Electric	(1,764,531,314.95)	
Gas	(237,982,586.85)	
Common	(86,277,137.00)	
Amortization of Plant		
Common	(20,656,095.44)	
Gas	(800.00)	
Electric	(100.00)	
Investments		30,117,248.39
Special Funds	29,511,083.19	
Ohio Valley Electric Corporation	594,286.00	
Nonutility Property	11,879.20	
Cash	36,121,124.88	36,121,124.88
Special Deposits		1,203,174.45
MAN Margin Call	506,695.37	
Other Special Deposits	696,479.08	
Temporary Cash Investments	38,421,281.63	38,421,281.63
Accounts Receivable - Less Reserve		115,617,416.71
Customers - Active	64,514,793.00	
Unbilled Revenues	43,684,976.46	
IMPA	2,182,068.26	
IMEA	2,174,850.42	
Wholesale Sales	2,056,338.03	
Sundry Accounts Receivable	933,628.39	
Transmission Sales	572,799.84	
Damage Claims	370,502.78	
Mutual Aid	131,132.13	
Bechtel Liquidated Damages	5,700.00	
Other	900,076.81	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	4,733,737.82	
Accrual	(3,876,016.79)	
Reserve	(1,761,214.00)	
Recoveries	(858,896.91)	
A/R Miscellaneous	(147,059.53)	
Accounts Receivable from Associated Companies		10,903,711.10
LG&E - KU Energy Services/Kentucky Utilities	10,691,575.54	
PPL Energy Funding	212,135.56	
Fuel		52,528,086.41
Coal 1,127,440.55 Tons @ $46.25; MMBtu 25,604,934.09 @ 203.63¢	52,138,617.20	
Fuel Oil 135,583.95 Gallons @ 248.99¢	337,586.18	
Gas Pipeline 4,700 Mcf @ $11.04	51,883.03	
Plant Materials and Operating Supplies		30,797,037.86
Regular Materials and Supplies	30,129,985.43	
Limestone 86,768.06 Tons @ $7.69	667,052.43	
Stores Expense Undistributed	5,476,575.61	5,476,575.61
Gas Stored Underground - Current		56,853,462.78
Gas Stored Underground* 12,065,509 Mcf (14.73 psia) @ $4.71	56,853,462.78	
Emission Allowances	2,772.88	2,772.88

October 26, 2011

Louisville Gas and Electric Company
Summary Trial Balance
September 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Prepayments		$ 6,339,120.25
Insurance	2,745,199.30	
Taxes	1,465,979.46	
Rights of Way	226,666.71	
Risk Management and Workers Compensation	90,000.00	
Franchises	23,028.75	
Other	1,788,246.03	
Miscellaneous Current Assets		761,979.55
Derivative Asset - Non-Hedging	761,979.55	
Unamortized Debt Expense		13,044,553.50
Trimble County 2000 Series A due 08/01/30 Var%	728,988.87	
Jefferson County 2001 Series A due 09/01/26 Var%	148,029.60	
Jefferson County 2001 Series A due 09/01/27 Var%	324,580.54	
Jefferson County 2001 Series B due 11/01/27 Var%	176,840.27	
Trimble County 2001 Series A due 09/01/26 Var%	160,950.59	
Trimble County 2001 Series B due 11/01/27 Var%	176,869.28	
Trimble County 2002 Series A due 10/01/32 Var%	781,649.67	
Louisville Metro 2003 Series A Due 10/01/33 1.900%	431,411.90	
Louisville Metro 2007 Series B Due 06/01/33 1.900%	161,946.64	
Trimble County 2007 Series A due 06/01/33 4.600%	1,029,912.26	
First Mortgage Bond due 11/15/15 1.625%	2,140,159.63	
First Mortgage Bond due 11/15/40 5.125%	3,462,448.38	
Revolving Credit Agreement	3,320,765.87	
Unamortized Loss on Bonds	21,025,622.90	21,025,622.90
Accumulated Deferred Income Taxes		26,152,975.69
Federal		
Electric	24,560,160.41	
Gas	(3,253,283.03)	
State		
Electric	5,413,256.17	
Gas	(567,157.86)	
Regulatory Assets		383,199,682.64
Pension and Postretirement Benefits	213,180,670.00	
Interest Rate Swap Ineffectiveness	57,262,328.87	
2009 Winter Storm	38,723,912.21	
2008 Wind Storm	20,793,960.63	
Deferred Taxes - ASC 740		
Federal		
Electric	12,544,305.85	
State		
Electric	2,287,715.35	
Swap Termination	9,001,840.76	
Asset Retirement Obligations		
Electric	8,200,112.61	
Gas	790,278.28	
Common	7,118.99	
2011 Summer Storm	7,419,650.67	
Gas Supply Clause/PBR	5,260,630.49	
Fuel Adjustment Clause	4,505,000.00	
MISO Exit Fee	947,091.30	
Rate Case Expenses	944,430.25	
KCCS Funding	621,945.36	
EKPC FERC Transmission Costs	409,799.92	
CMRG Funding	178,860.00	
General Management Audit	120,031.10	
Other Deferred Debits	1,330,450.74	1,330,450.74
Total Assets	$ 3,555,203,307.17	$ 3,555,203,307.17

* Excludes:

	$	Mcf
Non-recoverable Base Gas	9,648,855.00	7,880,000
Recoverable Base Gas	2,139,990.00	2,930,000
	11,788,845.00	10,810,000

October 26, 2011

Louisville Gas and Electric Company
Summary Trial Balance
September 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 1,382,841,866.62
Common Stock	425,170,424.09	
Less: Common Stock Expense	835,888.64	
Paid-In Capital	83,581,499.00	
Retained Earnings	874,925,832.17	
Pollution Control Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,261,577.46	531,261,577.46
Accounts Payable		81,366,680.34
Regular	78,454,143.65	
Salaries and Wages Accrued	2,879,594.53	
Employee Withholdings Payable	32,942.16	
Accounts Payable to Associated Companies		21,152,123.73
LG&E - KU Energy Services/Kentucky Utilities	21,152,123.73	
Customers' Deposits	22,546,494.46	22,546,494.46
Taxes Accrued	18,953,407.93	18,953,407.93
Interest Accrued		12,029,932.24
Jefferson County 2000 Series A due 05/01/27 5.375%	559,895.83	
Trimble County 2000 Series A due 08/01/30 Var%	4,166.75	
Jefferson County 2001 Series A due 09/01/26 Var%	6,164.39	
Jefferson County 2001 Series A due 09/01/27 Var%	157.17	
Jefferson County 2001 Series B due 11/01/27 Var%	5,080.55	
Trimble County 2001 Series A due 09/01/26 Var%	4,520.55	
Trimble County 2001 Series A due 10/01/32 Var%	1,598.11	
Trimble County 2001 Series B due 11/01/27 Var%	3,993.15	
Louisville Metro 2003 Series A due 10/01/33 1.900%	1,222,755.56	
Louisville Metro 2005 Series A due 02/01/35 5.750%	376,944.44	
Louisville Metro 2007 Series A due 06/01/33 5.625%	581,250.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%	224,791.11	
Trimble County 2007 Series A due 06/01/33 4.600%	920,000.00	
Interest Rate Swaps	694,986.09	
First Mortgage Bond due 11/15/15 1.625%	1,534,722.22	
First Mortgage Bond due 11/15/40 5.125%	5,517,916.67	
Customers' Deposits	343,388.68	
Interest Accrued on Tax Liabilities	14,000.00	
Other	13,600.97	
Miscellaneous Current and Accrued Liabilities		21,917,601.45
Vacation Pay Accrued	6,543,183.42	
Customer Overpayments	4,715,828.03	
ASC 815 Derivative Liability	4,283,486.06	
No-Notice Gas Payable	2,606,258.96	
Derivative Liabilities - Non-Hedging	1,124,150.90	
Tax Collections Payable	976,691.91	
Postretirement Benefits - Current	624,694.04	
Unearned Revenue	594,838.97	
Home Energy Assistance	392,485.11	
Service Deposit Refund Payable	(69,715.86)	
Other	125,699.91	

Louisville Gas and Electric Company
Summary Trial Balance
September 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Accumulated Deferred Income Taxes		$ 487,104,353.22
Federal		
Electric	343,555,580.54	
Gas	78,624,165.83	
State		
Electric	53,327,163.96	
Gas	11,597,442.89	
Investment Tax Credit		43,426,937.13
Advanced Coal Credit	23,296,568.00	
Job Development Credit		
Electric	19,540,335.98	
Gas	590,033.15	
Regulatory Liabilities		60,890,790.21
Deferred Taxes		
Federal		
Electric	40,447,541.45	
Gas	(11,524,437.19)	
State		
Electric	18,067,375.30	
Gas	(123,714.24)	
DSM Cost Recovery	6,191,134.10	
Gas Supply Clause/PBR	3,969,463.77	
Asset Retirement Obligations		
Gas	2,144,773.05	
Electric	274,746.64	
MISO Schedule 10 Charges	556,018.74	
Environmental Cost Recovery	456,056.00	
Purchased Gas Adjustment - Tennessee Gas	431,832.59	
Customers' Advances for Construction		8,049,779.58
Line Extensions		
Gas	6,495,926.69	
Electric	792,826.79	
Customer Advances - Museum Plaza	696,479.08	
Other	64,547.02	
Asset Retirement Obligations		55,794,013.83
Electric	34,303,675.93	
Gas	21,383,717.63	
Common	106,620.27	
Other Deferred Credits	29,396,986.25	29,396,986.25
Miscellaneous Long-Term Liabilities		58,630,593.68
Long-Term Derivative Liabilities - ASC 815	52,978,842.81	
Workers' Compensation	5,651,750.87	
Accumulated Provision for Benefits		145,536,169.04
Postretirement Benefits - ASC 715	80,406,627.36	
Pension Payable	61,662,688.50	
Post Employment Benefits Payable	3,698,041.00	
Post Employment Medicare Subsidy	(231,187.82)	
Total Liabilities and Stockholders' Equity	$ 3,555,203,307.17	$ 3,555,203,307.17

October 26, 2011

Louisville Gas and Electric Company
Statement of Cash Flows
September 30, 2011

	Year to Date	
	2011	2010
Cash Flows from Operating Activities		
Net income	$ 102,182,580.21	$ 106,880,808.86
Items not requiring (providing) cash currently:		
Depreciation	106,291,389.64	98,439,672.75
Amortization	6,011,506.42	5,835,257.86
Deferred income taxes - net	41,302,541.65	31,901,692.85
Investment tax credit - net	(2,097,639.00)	(1,876,331.00)
Gain on disposal of assets	(65,817.86)	(33,760.40)
Other	15,044,311.19	10,867,014.00
Change in receivables	57,646,816.79	2,291,134.50
Change in inventory	16,803,956.82	(11,159,166.31)
Change in allowance inventory	(43.92)	1,163.91
Change in payables and accrued expenses	40,702,557.81	(30,758,374.00)
Change in regulatory assets	(39,043,288.37)	(8,745,461.79)
Change in regulatory liabilities	9,464,441.75	(33,345,183.48)
Change in other deferred debits	(24,433,392.98)	(63,693.92)
Change in other deferred credits	23,931,830.50	20,675,744.23
Pension and postretirement funding	(67,940,500.00)	(24,267,900.00)
Other	(12,283,960.00)	(5,248,859.17)
Net cash provided (used) by operating activities	273,517,290.65	161,393,758.89
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(109,059,549.91)	(50,311,364.02)
Gross additions to common utility plant - construction expenditures	(5,604,877.81)	(8,960,809.07)
Proceeds received from sales of property	65,817.86	34,136.95
Change in restricted cash	(10,749,228.80)	-
Change in derivatives	-	94,507.35
Reissuance of reacquired bonds as Available for Sale debt securities	163,200,000.00	-
Other	(7,525,344.99)	-
Net cash provided (used) by investing activities	30,326,816.35	(59,143,528.79)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(1,301,712.33)	(26,566.81)
Net change in short-term debt	(174,876,000.00)	(48,515,000.00)
Dividends on common stock	(55,250,000.00)	(55,000,000.00)
Net cash provided (used) by financing activities	(231,427,712.33)	(103,541,566.81)
Net Increase (Decrease) in Cash and Cash Equivalents	72,416,394.67	(1,291,336.71)
Cash and Cash Equivalents at Beginning of Period	2,126,011.84	5,195,486.38
Cash and Cash Equivalents at End of Period	$ 74,542,406.51	$ 3,904,149.67

October 26, 2011

Louisville Gas and Electric 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						
Jefferson County 2000 Series A due 05/01/27 5.375%.......................	$ 111,979.15	$ 111,979.17	$ 1,007,812.52	$ 1,007,812.41	$ 1,343,750.03	$ 1,343,749.92
Trimble County 2000 Series A due 08/01/30 Var%............................	12,500.26	32,986.76	148,093.19	301,232.86	238,141.29	356,372.82
Jefferson County 2001 Series A due 09/01/26 Var%..........................	1,178.80	3,852.15	16,329.05	35,275.58	28,188.60	41,197.67
Jefferson County 2001 Series A due 09/01/27 Var%..........................	7,027.41	18,493.15	148,093.17	127,417.82	209,582.90	175,037.69
Jefferson County 2001 Series B due 11/01/27 Var%..........................	15,953.43	36,428.77	229,310.71	278,546.24	307,269.60	362,402.40
Trimble County 2001 Series A due 09/01/26 Var%............................	6,615.07	11,602.73	75,884.95	127,306.17	113,593.85	189,689.73
Trimble County 2001 Series A due 10/01/32 Var%............................	8,492.82	15,513.08	97,295.18	243,369.64	148,892.43	269,023.88
Trimble County 2001 Series B due 11/01/27 Var%............................	15,821.92	35,575.34	226,492.86	278,878.00	304,164.08	362,734.14
Louisville Metro 2003 Series A due 10/01/33 1.900%.......................	202,666.67	-	1,749,688.78	-	1,749,688.78	48,681.54
Louisville Metro 2005 Series A due 02/01/35 5.750%.......................	191,666.66	191,666.67	1,724,999.98	1,724,999.90	2,299,999.99	2,299,999.91
Louisville Metro 2007 Series A due 06/01/33 5.625%.......................	145,312.49	145,312.50	1,307,812.41	1,307,812.45	1,743,749.91	1,743,749.95
Louisville Metro 2007 Series B due 06/01/33 1.900%........................	55,733.34	-	481,164.48	-	481,164.48	-
Trimble County 2007 Series A due 06/01/33 4.600%.........................	230,000.00	230,000.00	2,070,000.00	2,070,000.00	2,760,000.00	2,760,000.00
Interest Rate Swaps..	694,986.12	210,382.37	5,817,449.99	5,712,071.67	7,803,718.63	7,066,971.84
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/15/15 1.625%..	338,541.66	-	3,046,874.99	-	3,554,687.50	-
First Mortgage Bond due 11/15/40 5.125%..	1,217,187.50	-	10,954,687.50	-	12,780,468.75	-
Fidelia/PPL..	-	2,220,150.01	-	19,981,350.03	3,339,225.00	26,641,800.04
Revolving Credit Agreement...	-	-	185,005.01	-	779,683.35	-
Total..	3,255,663.30	3,263,942.70	29,286,994.77	33,196,072.77	39,985,969.17	43,661,411.53
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense..	179,497.91	15,546.83	1,583,704.84	139,779.02	1,897,300.83	186,333.48
Amortization of Loss on Reacquired Debt..	101,002.97	101,002.98	909,026.73	908,241.79	1,212,035.67	1,210,555.03
Total..	280,500.88	116,549.81	2,492,731.57	1,048,020.81	3,109,336.50	1,396,888.51
Other Interest Charges						
Customers' Deposits...	113,846.07	105,824.09	1,043,265.03	1,032,445.81	1,399,725.68	1,580,561.80
Other Tax Deficiencies..	14,000.00	3,525.00	14,000.00	10,994.00	(14,494.00)	8,967.00
Interest on DSM Cost Recovery..	1,546.79	2,342.34	10,923.03	19,730.63	17,607.64	29,496.19
Interest on Debt to Associated Companies..	39.65	22,634.30	8,901.65	235,871.91	35,451.62	319,526.46
Other Interest Expense...	108,806.12	129,530.81	828,287.45	695,131.11	1,075,926.51	823,442.74
Total..	238,238.63	263,856.54	1,905,377.16	1,994,173.46	2,514,217.45	2,761,994.19
Total Interest..	$ 3,774,402.81	$ 3,644,349.05	$ 33,685,103.50	$ 36,238,267.04	$ 45,609,523.12	$ 47,820,294.23

October 26, 2011

Louisville Gas and Electric 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	$ 1,998,957.00	$ 1,222,746.10	$ 13,600,269.00	$ 11,003,481.58
Unemployment	3,423.49	3,529.53	121,698.19	132,120.68
FICA	622,186.43	553,222.67	5,939,560.63	5,289,072.07
Public Service Commission Fee	162,886.60	161,096.90	1,455,241.24	1,453,343.24
Federal Income	(3,676,576.81)	(6,683,028.40)	13,849,665.33	24,328,238.85
State Income	(167,428.46)	(1,354,225.08)	8,207,099.07	2,449,578.74
Miscellaneous	3,246.57	-	36,577.16	27,356.53
Total Charged to Operating Expense	(1,053,305.18)	(6,096,658.28)	43,210,110.62	44,683,191.69
Taxes Charged to Other Accounts	(1,440,906.35)	7,620,655.81	732,879.03	6,872,512.98
Taxes Accrued on Intercompany Accounts	(32,729.35)	(257,956.48)	(1,827,411.68)	(2,192,960.65)
Total Taxes Charged	$ (2,526,940.88)	$ 1,266,041.05	$ 42,115,577.97	$ 49,362,744.02

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	$ 11,354,131.66	$ 13,725,085.25	$ 11,553,915.92	$ 13,525,300.99
Unemployment	54,386.05	87,965.99	141,918.21	433.83
FICA	590,648.24	4,900,226.08	4,903,531.30	587,343.02
Federal Income	(3,741,320.05)	12,350,932.23	4,753,055.00	3,856,557.18
State Income	229,108.93	7,933,773.89	7,616,999.44	545,883.38
Kentucky Sales and Use Tax	1,088,857.95	3,006,813.86	3,680,055.91	415,615.90
Miscellaneous	22,339.97	110,780.67	110,847.01	22,273.63
Totals	$ 9,598,152.75	$ 42,115,577.97	$ 32,760,322.79	$ 18,953,407.93

October 26, 2011

Louisville Gas and Electric Company
Summary of Utility Plant
September 30, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant In Service**						
Common						
Common General Plant..	$ 159,884,459.36	$ 9,595,224.90	$ (663,361.41)	$ (30,818.06)	$ 8,901,045.43	$ 168,785,504.79
Common Intangible Plant......................................	56,455,326.72	7,964,495.57	(1,661,801.58)	-	6,302,693.99	62,758,020.71
	216,339,786.08	17,559,720.47	(2,325,162.99)	(30,818.06)	15,203,739.42	231,543,525.50
Electric						
Electric Distribution...	927,289,038.50	31,066,492.50	(6,291,741.15)	47,153.43	24,821,904.78	952,110,943.28
Electric General Plant..	16,521,615.59	1,289,339.27	(1,934,885.80)	30,818.06	(614,728.47)	15,906,887.12
Electric Hydro Production.....................................	41,680,209.14	910,668.82	(229,891.00)	-	680,777.82	42,360,986.96
Electric Intangible Plant...	2,340.29	-	-	-	-	2,340.29
Electric Other Production......................................	229,401,033.01	1,886,947.59	(981,817.87)	38,429.14	943,558.86	230,344,591.87
Electric Steam Production......................................	1,930,347,044.43	201,354,557.85	(23,221,870.86)	3,530,527.24	181,663,214.23	2,112,010,258.66
Electric Transmission...	247,742,496.14	6,354,349.01	(1,124,347.60)	(47,153.43)	5,182,847.98	252,925,344.12
	3,392,983,777.10	242,862,355.04	(33,784,554.28)	3,599,774.44	212,677,575.20	3,605,661,352.30
Gas						
Gas Distribution...	549,799,120.70	34,872,795.04	(585,227.95)	97,729.20	34,385,296.29	584,184,416.99
Gas General Plant..	9,178,093.57	400,882.53	(995,401.23)	(97,729.20)	(692,247.90)	8,485,845.67
Gas Intangible Plant...	1,187.49	-	-	-	-	1,187.49
Gas Storage..	78,415,311.06	2,114,137.15	(1,426,316.42)	-	687,820.73	79,103,131.79
Gas Transmission...	16,661,869.68	970,087.61	(18,360.47)	3,941,518.65	4,893,245.79	21,555,115.47
	654,055,582.50	38,357,902.33	(3,025,306.07)	3,941,518.65	39,274,114.91	693,329,697.41
Total 101 Accounts……………………………….	4,263,379,145.68	298,779,977.84	(39,135,023.34)	7,510,475.03	267,155,429.53	4,530,534,575.21
105 **Plant Held For Future Use**						
Electric						
Electric Distribution...	649,014.48	-	-	-	-	649,014.48
Electric Steam Production......................................	4,182,559.70	-	-	(4,182,559.70)	(4,182,559.70)	-
	4,831,574.18	-	-	(4,182,559.70)	(4,182,559.70)	649,014.48
Total 105001………………………………………	$ 4,831,574.18	$ -	$ -	$ (4,182,559.70)	$ (4,182,559.70)	$ 649,014.48

Louisville Gas and Electric Company
Summary of Utility Plant
September 30, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
106 **Completed Construction Not Classified**						
Common						
Common General Plant	$ 597,158.63	$ 1,359,099.42	$ -	$ -	$ 1,359,099.42	$ 1,956,258.05
Common Intangible Plant	2,714,931.36	(1,575,075.77)	-	-	(1,575,075.77)	1,139,855.59
	3,312,089.99	(215,976.35)	-	-	(215,976.35)	3,096,113.64
Electric						
Electric Distribution	11,544,733.90	7,019,806.75	-	-	7,019,806.75	18,564,540.65
Electric General Plant	50,763.87	(50,763.87)	-	-	(50,763.87)	-
Electric Hydro Production	16,952.26	174,504.11	-	-	174,504.11	191,456.37
Electric Intangible Plant	-	-	-	-	-	-
Electric Other Production	1,767,208.21	585,175.71	-	-	585,175.71	2,352,383.92
Electric Steam Production	15,929,229.77	9,450,122.71	-	-	9,450,122.71	25,379,352.48
Electric Transmission	35,045,472.82	1,010,992.42	-	-	1,010,992.42	36,056,465.24
	64,354,360.83	18,189,837.83	-	-	18,189,837.83	82,544,198.66
Gas						
Gas Distribution	24,420,156.16	(3,874,780.78)	-	-	(3,874,780.78)	20,545,375.38
Gas General Plant	126,992.17	74,776.30	-	-	74,776.30	201,768.47
Gas Intangible Plant	-	-	-	-	-	-
Gas Storage	951,426.06	492,034.09	-	-	492,034.09	1,443,460.15
Gas Transmission	-	1,335,701.67	-	-	1,335,701.67	1,335,701.67
	25,498,574.39	(1,972,268.72)	-	-	(1,972,268.72)	23,526,305.67
Total 106 Accounts	93,165,025.21	16,001,592.76	-	-	16,001,592.76	109,166,617.97
117 **Gas Stored Underground-Noncurrent**						
Gas						
Gas Stored Nonrecoverable	2,139,990.00	-	-	-	-	2,139,990.00
	2,139,990.00	-	-	-	-	2,139,990.00
Total 117001	2,139,990.00	-	-	-	-	2,139,990.00
121 **Nonutility Property**						
Common						
Non Utility Property	75,239.56	-	-	-	-	75,239.56
	75,239.56	-	-	-	-	75,239.56
Total 121001	75,239.56	-	-	-	-	75,239.56
107 **Construction Work In Progress**						
Common	21,243,879.89	(11,738,866.31)	-	-	(11,738,866.31)	9,505,013.58
Electric	324,323,732.14	(177,183,945.04)	-	-	(177,183,945.04)	147,139,787.10
Gas	39,756,306.91	(4,136,241.81)	-	-	(4,136,241.81)	35,620,065.10
	385,323,918.94	(193,059,053.16)	-	-	(193,059,053.16)	192,264,865.78
Total Plant (Non-CWIP)	4,363,590,974.63	314,781,570.60	(39,135,023.34)	3,327,915.33	278,974,462.59	4,642,565,437.22
Total Plant + CWIP	4,748,914,893.57	121,722,517.44	(39,135,023.34)	3,327,915.33	85,915,409.43	4,834,830,303.00
Total Plant + CWIP - Non Utility	$ 4,748,839,654.01	$ 121,722,517.44	$ (39,135,023.34)	$ 3,327,915.33	$ 85,915,409.43	$ 4,834,755,063.44

October 26, 2011

Louisville Gas and Electric 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										
Common General Plant...	$ (77,263,235.10)	$ (9,590,503.37)	$ 663,361.41	$ 30,818.06	$ -	$ -	$ -	$ -	$ -	$ (86,159,559.00)
Common General Plant - ARO..	(343.19)	(1,545.30)	-	-	-	-	-	-	-	(1,888.49)
Electric Distribution...	(277,000,365.75)	(13,009,011.07)	6,291,741.15	(382.60)	-	-	-	-	-	(283,718,018.27)
Electric Distribution - ARO...	(1,256.54)	(4,525.39)	-	-	-	-	-	-	-	(5,781.93)
Electric General Plant..	(12,910,034.19)	(305,451.83)	1,934,885.80	(30,818.06)	-	-	-	-	-	(11,311,418.28)
Electric Hydro Production...	(9,718,276.66)	(422,048.70)	229,891.00	-	-	-	-	-	-	(9,910,434.36)
Electric Hydro Production - ARO..	(364.10)	(1,311.39)	-	-	-	-	-	-	-	(1,675.49)
Electric Other Production..	(60,282,055.17)	(6,138,430.87)	981,817.87	-	-	-	-	-	-	(65,438,668.17)
Electric Other Production - ARO...	(192.68)	(820.46)	-	-	-	-	-	-	-	(1,013.14)
Electric Steam Production...	(1,029,518,070.37)	(42,570,672.20)	22,546,194.50	-	-	-	-	-	-	(1,049,542,548.07)
Electric Steam Production - ARO..	(204,061.94)	(1,586,589.96)	675,676.36	116,513.06	-	-	-	-	-	(998,462.48)
Electric Transmission..	(119,192,606.75)	(3,286,997.09)	1,124,347.60	382.60	-	-	-	-	-	(121,354,873.64)
Electric Transmission - ARO...	(41.40)	(149.13)	-	-	-	-	-	-	-	(190.53)
Gas Distribution...	(125,049,477.23)	(8,650,428.74)	510,188.68	(13,332.40)	-	-	-	-	-	(133,203,049.69)
Gas Distribution - ARO...	(49,734.93)	(297,397.52)	75,039.27	-	-	-	-	-	-	(272,093.18)
Gas General Plant..	(6,299,629.20)	(236,278.05)	995,401.23	13,332.40	-	-	-	-	-	(5,527,173.62)
Gas Storage..	(31,288,281.49)	(811,047.39)	1,030,910.96	-	-	-	-	-	-	(31,068,417.92)
Gas Storage - ARO..	(39,466.10)	(558,445.22)	395,405.46	-	-	-	-	-	-	(202,505.86)
Gas Stored Nonrecoverable...	-	-	-	-	-	-	-	-	-	-
Gas Transmission..	(9,448,605.32)	(42,890.94)	18,360.47	-	-	-	-	-	-	(9,473,135.79)
Gas Transmission - ARO...	-	(8,817.73)	-	-	-	-	-	-	-	(8,817.73)
Non Utility Property...	(63,360.36)	-	-	-	-	-	-	-	-	(63,360.36)
	(1,758,329,458.47)	(87,523,362.35)	37,473,221.76	116,513.06	-	-	-	-	-	(1,808,263,086.00)
Cost Of Removal										
Common General Plant...	(688,372.47)	(210,386.61)	-	-	-	-	332,962.76	-	-	(565,796.32)
Electric Distribution...	(146,715,298.78)	(5,152,771.86)	-	(55.48)	-	-	3,619,630.52	-	-	(148,248,495.60)
Electric General Plant..	3,866.64	-	-	-	-	-	-	-	-	3,866.64
Electric Hydro Production...	736,907.70	(32,051.34)	-	-	-	-	38,351.42	-	-	743,207.78
Electric Other Production..	(2,505,175.99)	(263,442.24)	-	-	-	-	110,974.17	-	-	(2,657,644.06)
Electric Steam Production...	(94,783,295.15)	(12,727,717.57)	-	-	-	-	2,591,182.83	-	-	(104,919,829.89)
Electric Transmission..	(24,538,454.78)	(1,057,865.36)	-	55.48	-	-	82,331.47	-	-	(25,513,933.19)
Gas Distribution...	(60,212,131.14)	(2,443,316.43)	-	-	-	-	1,480,225.35	-	-	(61,175,222.22)
Gas General Plant..	(0.02)	-	-	-	-	-	-	-	-	(0.02)
Gas Storage..	(170,437.90)	(105,206.78)	-	-	-	-	565,052.30	-	-	289,407.62
Gas Stored Nonrecoverable...	-	-	-	-	-	-	-	-	-	-
Gas Transmission..	(3,016,813.95)	(10,611.03)	-	-	-	-	46,318.45	-	-	(2,981,106.53)
Non Utility Property...	-	-	-	-	-	-	-	-	-	-
	$ (331,889,205.84)	$ (22,003,369.22)	$ -	$ -	$ -	$ -	$ 8,867,029.27	$ -	$ -	$ (345,025,545.79)

October 26, 2011

Louisville Gas and Electric 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
Salvage										
Common General Plant	$ 278,074.55	$ 287.46	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 278,362.01
Electric Distribution	17,535,024.98	1,044,146.28	-	-	-	-	-	(197,553.22)	-	18,381,618.04
Electric General Plant	138,281.25	1,732.95	-	-	-	-	-	-	-	140,014.20
Electric Hydro Production	376,638.17	-	-	-	-	-	-	-	-	376,638.17
Electric Other Production	(18,998.67)	-	-	-	-	-	-	-	-	(18,998.67)
Electric Steam Production	22,028,570.14	1,516,393.90	-	-	-	-	-	(34,636.38)	-	23,510,327.66
Electric Transmission	6,247,368.67	196,105.34	-	-	-	-	-	-	-	6,443,474.01
Gas Distribution	3,594,440.75	149,224.52	-	-	-	-	-	-	-	3,743,665.27
Gas General Plant	225,788.37	1,701.73	-	-	-	-	-	-	-	227,490.10
Gas Storage	269,933.04	12,876.33	-	-	-	-	-	-	-	282,809.37
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	217,923.11	3,979.13	-	-	-	-	-	-	-	221,902.24
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	50,893,044.36	2,926,447.64	-	-	-	-	-	(232,189.60)	-	53,587,302.40
Total Reserves										
Common	(77,737,236.57)	(9,802,147.82)	663,361.41	30,818.06	-	-	332,962.76	-	-	(86,512,242.16)
Electric	(1,730,321,891.37)	(83,801,477.99)	33,784,554.28	85,695.00	-	-	6,442,470.41	(232,189.60)	-	(1,774,042,839.27)
Gas	(231,266,492.01)	(12,996,658.12)	3,025,306.07	0.00	-	-	2,091,596.10	-	-	(239,146,247.96)
	(2,039,325,619.95)	(106,600,283.93)	37,473,221.76	116,513.06	-	-	8,867,029.27	(232,189.60)	-	(2,099,701,329.39)
Retirement Work In Progress										
Common	342,947.00	-	-	162,020.85	-	(332,962.76)	18,488.79	(20,894.00)	2,144.92	171,744.80
Electric	9,603,653.21	-	-	(78,968.13)	(909,868.03)	(5,868,658.02)	7,387,311.16	(438,968.10)	(182,977.77)	9,511,524.32
Gas	2,523,160.64	-	-	(23,759.86)	(1,053,809.06)	(1,295,792.38)	1,021,237.93	(4,846.40)	(2,529.76)	1,163,661.11
	12,469,760.85	-	-	59,292.86	(1,963,677.09)	(7,497,413.16)	8,427,037.88	(464,708.50)	(183,362.61)	10,846,930.23
YTD ACTIVITY	(2,026,855,859.10)	(106,600,283.93)	37,473,221.76	175,805.92	(1,963,677.09)	(7,497,413.16)	17,294,067.15	(696,898.10)	(183,362.61)	(2,088,854,399.16)
Amortization										
Common	(16,306,390.60)	(6,011,506.42)	1,661,801.58	-	-	-	-	-	-	(20,656,095.44)
Electric	(100.00)	-	-	-	-	-	-	-	-	(100.00)
Gas	(800.00)	-	-	-	-	-	-	-	-	(800.00)
AMORTIZATION TOTAL	(16,307,290.60)	(6,011,506.42)	1,661,801.58	-	-	-	-	-	-	(20,656,995.44)
Depreciation & Amortization Total	$ (2,043,163,149.70)	$ (112,611,790.35)	$ 39,135,023.34	$ 175,805.92	$ (1,963,677.09)	$ (7,497,413.16)	$ 17,294,067.15	$ (696,898.10)	$ (183,362.61)	$ (2,109,511,394.60)
Depr & Amort - Nonutility for Balance Sheet										(2,109,448,034.24)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)	$ 2,705,739,864.67									$ 2,725,307,029.20

October 26, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
September 30, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues.......................................	$ 86,259,338.17	$ -	$ 86,259,338.17
Gas Operating Revenues...	12,116,422.24	-	12,116,422.24
Total Operating Revenues..	98,375,760.41	-	98,375,760.41
Fuel for Electric Generation..	30,046,419.94	-	30,046,419.94
Power Purchased...	5,507,089.89	-	5,507,089.89
Gas Supply Expenses..	4,361,801.03	-	4,361,801.03
Other Operation Expenses...	18,985,899.75	-	18,985,899.75
Maintenance..	3,499,646.07	-	3,499,646.07
Depreciation..	11,821,283.70	-	11,821,283.70
Amortization Expense...	691,375.44	-	691,375.44
Regulatory Credits...	(367,360.47)	-	(367,360.47)
Taxes			
Federal Income...	(3,676,576.81)	-	(3,676,576.81)
State Income..	(167,428.46)	-	(167,428.46)
Deferred Federal Income - Net.................................	8,906,276.75	8,292.58	8,914,569.33
Deferred State Income - Net.....................................	893,120.86	1,512.31	894,633.17
Property and Other...	2,790,700.09	-	2,790,700.09
Amortization of Investment Tax Credit....................	(236,034.00)	-	(236,034.00)
Loss (Gain) from Disposition of Allowances...............	-	-	-
Accretion Expense..	202,763.84	-	202,763.84
Total Operating Expenses..	83,258,977.62	9,804.89	83,268,782.51
Net Operating Income...	15,116,782.79	(9,804.89)	15,106,977.90
Other Income Less Deductions.................................	153,501.78	-	153,501.78
Income Before Interest Charges................................	15,270,284.57	(9,804.89)	15,260,479.68
Interest on Long-Term Debt..	3,255,663.30	(25,017.63)	3,230,645.67
Amortization of Debt Expense - Net...........................	280,500.88	-	280,500.88
Other Interest Expenses...	238,238.63	-	238,238.63
Total Interest Charges..	3,774,402.81	(25,017.63)	3,749,385.18
Net Income..	$ 11,495,881.76	$ 15,212.74	$ 11,511,094.50

Note: Purchase accounting is subject to change through October 31, 2011

October 26, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
September 30, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 815,825,290.81	$ -	$ 815,825,290.81
Gas Operating Revenues	217,995,494.08	-	217,995,494.08
Total Operating Revenues	1,033,820,784.89	-	1,033,820,784.89
Fuel for Electric Generation	273,795,119.05	-	273,795,119.05
Power Purchased	55,261,418.82	-	55,261,418.82
Gas Supply Expenses	116,873,598.02	-	116,873,598.02
Other Operation Expenses	177,460,624.64	27,884.66	177,488,509.30
Maintenance	85,828,056.49	-	85,828,056.49
Depreciation	106,291,389.64	-	106,291,389.64
Amortization Expense	6,011,506.42	-	6,011,506.42
Regulatory Credits	(4,410,876.53)	-	(4,410,876.53)
Taxes			
Federal Income	13,849,665.33	-	13,849,665.33
State Income	8,207,099.07	-	8,207,099.07
Deferred Federal Income - Net	38,273,146.38	64,964.95	38,338,111.33
Deferred State Income - Net	46,411.06	11,847.72	58,258.78
Property and Other	21,153,346.23	-	21,153,346.23
Amortization of Investment Tax Credit	(2,097,639.00)	-	(2,097,639.00)
Loss (Gain) from Disposition of Allowances	(2,577.94)	-	(2,577.94)
Accretion Expense	1,951,274.43	-	1,951,274.43
Total Operating Expenses	898,491,562.11	104,697.33	898,596,259.44
Net Operating Income	135,329,222.78	(104,697.33)	135,224,525.45
Other Income Less Deductions	538,460.93	-	538,460.93
Income Before Interest Charges	135,867,683.71	(104,697.33)	135,762,986.38
Interest on Long-Term Debt	29,286,994.77	(225,158.67)	29,061,836.10
Amortization of Debt Expense - Net	2,492,731.57	-	2,492,731.57
Other Interest Expenses	1,905,377.16	-	1,905,377.16
Total Interest Charges	33,685,103.50	(225,158.67)	33,459,944.83
Net Income	$ 102,182,580.21	$ 120,461.34	$ 102,303,041.55

Note: Purchase accounting is subject to change through October 31, 2011

October 26, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
September 30, 2011

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……………………………	$ 863,429,950.41	$ 810,873,011.74	$ (808,794,033.84)	$ -	$ 54,635,916.57	$ 810,873,011.74
Add:						
Net Income (Loss) for Period…………………………	11,495,881.76	21,286,663.36	15,212.74	-	11,511,094.50	21,286,663.36
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	-	25,000,000.00	-	-	-	25,000,000.00
Balance at End of Period…………………………………	$ 874,925,832.17	$ 807,159,675.10	$ (808,778,821.10)	$ -	$ 66,147,011.07	$ 807,159,675.10

Note: Purchase accounting is subject to change through October 31, 2011

October 26, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
September 30, 2011

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period…………………………….	$ 827,993,251.96	$ 755,278,866.24	$ (808,899,282.44)	$ -	$ 19,093,969.52	$ 755,278,866.24
Add:						
Net Income (Loss) for Period…………………………	102,182,580.21	106,880,808.86	120,461.34	-	102,303,041.55	106,880,808.86
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	55,250,000.00	55,000,000.00	-	-	55,250,000.00	55,000,000.00
Balance at End of Period……………………………………	$ 874,925,832.17	$ 807,159,675.10	$ (808,778,821.10)	$ -	$ 66,147,011.07	$ 807,159,675.10

Note: Purchase accounting is subject to change through October 31, 2011

October 26, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
September 30, 2011

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period	$ 807,159,675.10	$ 736,266,409.68	$ -	$ -	$ 807,159,675.10	$ 736,266,409.68
Add:						
Net Income (Loss) for Period	123,016,157.07	125,893,265.42	168,070.42	-	123,184,227.49	125,893,265.42
Deduct:						
Adjustment to Retained Earnings	-	-	808,946,891.52	-	808,946,891.52	-
Common Dividends						
Common Stock Without Par Value	55,250,000.00	55,000,000.00	-	-	55,250,000.00	55,000,000.00
Balance at End of Period	$ 874,925,832.17	$ 807,159,675.10	$ (808,778,821.10)	$ -	$ 66,147,011.07	$ 807,159,675.10

Note: Purchase accounting is subject to change through October 31, 2011

October 26, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of September 30, 2011

Assets	Without Purchase Accounting	Purchase Accounting	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 4,834,755,063.44	$ -	$ 4,834,755,063.44
Less: Reserves for Depreciation and Amortization....	2,109,448,034.24	-	2,109,448,034.24
Total..	2,725,307,029.20	-	2,725,307,029.20
Investments			
Ohio Valley Electric Corporation.............................	594,286.00	-	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	-	11,879.20
Special Funds...	29,511,083.19	-	29,511,083.19
Total..	30,117,248.39	-	30,117,248.39
Current and Accrued Assets			
Cash..	36,121,124.88	-	36,121,124.88
Special Deposits..	1,203,174.45	-	1,203,174.45
Temporary Cash Investments...................................	38,421,281.63	-	38,421,281.63
Accounts Receivable - Less Reserve.........................	115,617,416.71	-	115,617,416.71
Accounts Receivable from Associated Companies....	10,903,711.10	-	10,903,711.10
Materials and Supplies - At Average Cost			
Fuel..	52,528,086.41	-	52,528,086.41
Plant Materials and Operating Supplies.................	30,797,037.86	-	30,797,037.86
Stores Expense...	5,476,575.61	-	5,476,575.61
Gas Stored Underground.......................................	56,853,462.78	-	56,853,462.78
Emission Allowances...	2,772.88	-	2,772.88
Prepayments..	6,339,120.25	-	6,339,120.25
Miscellaneous Current and Accrued Assets..............	761,979.55	-	761,979.55
Total..	355,025,744.11	-	355,025,744.11
Deferred Debits and Other			
Unamortized Debt Expense......................................	13,044,553.50	(3,527,821.08)	9,516,732.42
Unamortized Loss on Bonds....................................	21,025,622.90	-	21,025,622.90
Accumulated Deferred Income Taxes.......................	26,152,975.69	72,399,448.49	98,552,424.18
Deferred Regulatory Assets.....................................	383,199,682.64	10,172,208.54	393,371,891.18
Other Deferred Debits..	1,330,450.74	173,170,923.64	174,501,374.38
Goodwill..	-	389,157,351.59	389,157,351.59
Total..	444,753,285.47	641,372,111.18	1,086,125,396.65
Total Assets..	$ 3,555,203,307.17	$ 641,372,111.18	$ 4,196,575,418.35

Note: Purchase accounting is subject to change through October 31, 2011

October 26, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of September 30, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting	Total
Proprietary Capital			
Common Stock	$ 425,170,424.09	$ -	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	-	835,888.64
Paid-In Capital	83,581,499.00	1,194,085,869.02	1,277,667,368.02
Other Comprehensive Income	-	-	-
Retained Earnings	874,925,832.17	(808,778,821.10)	66,147,011.07
Total Proprietary Capital	1,382,841,866.62	385,307,047.92	1,768,148,914.54
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	6,301,523.07	580,605,523.07
First Mortgage Bonds	531,261,577.46	-	531,261,577.46
LT Notes Payable to Associated Companies	-	-	-
Total Long-Term Debt	1,105,565,577.46	6,301,523.07	1,111,867,100.53
Total Capitalization	2,488,407,444.08	391,608,570.99	2,880,016,015.07
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies	-	-	-
Accounts Payable	81,366,680.34	-	81,366,680.34
Accounts Payable to Associated Companies	21,152,123.73	-	21,152,123.73
Customer Deposits	22,546,494.46	-	22,546,494.46
Taxes Accrued	18,953,407.93	-	18,953,407.93
Dividends Declared	-	-	-
Interest Accrued	12,029,932.24	-	12,029,932.24
Miscellaneous Current and Accrued Liabilities	21,917,601.45	-	21,917,601.45
Total	177,966,240.15	-	177,966,240.15
Deferred Credits and Other			
Accumulated Deferred Income Taxes	487,104,353.22	69,948,229.09	557,052,582.31
Investment Tax Credit	43,426,937.13	-	43,426,937.13
Regulatory Liabilities	60,890,790.21	173,170,923.64	234,061,713.85
Customer Advances for Construction	8,049,779.58	-	8,049,779.58
Asset Retirement Obligations	55,794,013.83	-	55,794,013.83
Other Deferred Credits	29,396,986.25	6,644,387.46	36,041,373.71
Miscellaneous Long-Term Liabilities	58,630,593.68	-	58,630,593.68
Misc Long-Term Liab Due to Assoc Cos	-	-	-
Accum Provision for Postretirement Benefits	145,536,169.04	-	145,536,169.04
Total	888,829,622.94	249,763,540.19	1,138,593,163.13
Total Liabilities and Stockholders' Equity	$ 3,555,203,307.17	$ 641,372,111.18	$ 4,196,575,418.35

Note: Purchase accounting is subject to change through October 31, 2011

October 26, 2011

LOUISVILLE GAS AND ELECTRIC COMPANY

Financial Reports

August 31, 2011

Index
Financial and Operating Reports

Louisville Gas and Electric 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.

Louisville Gas and Electric Company
Comparative Statement of Income
August 31, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 105,479,442.77	$ 115,532,372.93	$ (10,052,930.16)	(8.70)
Gas Operating Revenues	11,482,287.79	10,595,819.49	886,468.30	8.37
Total Operating Revenues	116,961,730.56	126,128,192.42	(9,166,461.86)	(7.27)
Fuel for Electric Generation	34,727,105.86	35,921,789.34	(1,194,683.48)	(3.33)
Power Purchased	5,404,608.23	4,089,503.48	1,315,104.75	32.16
Gas Supply Expenses	4,257,401.19	4,140,897.12	116,504.07	2.81
Other Operation Expenses	21,424,773.59	21,009,294.71	415,478.88	1.98
Maintenance	15,528,306.75	7,518,626.91	8,009,679.84	106.53
Depreciation	11,790,920.26	11,046,026.33	744,893.93	6.74
Amortization Expense	689,697.43	622,780.64	66,916.79	10.74
Regulatory Credits	(360,697.95)	(185,053.04)	(175,644.91)	(94.92)
Taxes				
Federal Income	5,664,531.39	11,783,267.74	(6,118,736.35)	(51.93)
State Income	1,033,045.23	2,148,924.21	(1,115,878.98)	(51.93)
Deferred Federal Income - Net	258,724.10	-	258,724.10	100.00
Deferred State Income - Net	(624,726.66)	-	(624,726.66)	(100.00)
Property and Other	2,309,427.14	1,964,987.36	344,439.78	17.53
Investment Tax Credit	-	-	-	-
Amortization of Investment Tax Credit	(236,034.00)	(208,481.00)	(27,553.00)	(13.22)
Loss (Gain) from Disposition of Allowances	-	-	-	-
Accretion Expense	216,401.98	170,413.28	45,988.70	26.99
Total Operating Expenses	102,083,484.54	100,022,977.08	2,060,507.46	2.06
Net Operating Income	14,878,246.02	26,105,215.34	(11,226,969.32)	(43.01)
Other Income Less Deductions	233,969.18	1,302,017.26	(1,068,048.08)	(82.03)
Income Before Interest Charges	15,112,215.20	27,407,232.60	(12,295,017.40)	(44.86)
Interest on Long-Term Debt	3,201,192.23	3,746,405.73	(545,213.50)	(14.55)
Amortization of Debt Expense - Net	279,566.93	116,549.81	163,017.12	139.87
Other Interest Expenses	275,342.27	150,336.28	125,005.99	83.15
Total Interest Charges	3,756,101.43	4,013,291.82	(257,190.39)	(6.41)
Net Income	$ 11,356,113.77	$ 23,393,940.78	$ (12,037,827.01)	(51.46)

September 22, 2011

Louisville Gas and Electric Company
Comparative Statement of Income
August 31, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 729,565,952.64	$ 697,203,098.41	$ 32,362,854.23	4.64
Gas Operating Revenues..	205,879,071.84	189,509,520.21	16,369,551.63	8.64
Total Operating Revenues...	935,445,024.48	886,712,618.62	48,732,405.86	5.50
Fuel for Electric Generation..	243,748,699.11	245,219,518.93	(1,470,819.82)	(0.60)
Power Purchased...	49,754,328.93	37,291,207.27	12,463,121.66	33.42
Gas Supply Expenses...	112,511,796.99	103,766,169.26	8,745,627.73	8.43
Other Operation Expenses..	158,474,724.89	147,617,418.23	10,857,306.66	7.36
Maintenance...	82,328,410.42	68,983,035.94	13,345,374.48	19.35
Depreciation...	94,470,105.94	87,086,930.22	7,383,175.72	8.48
Amortization Expense..	5,320,130.98	5,212,498.44	107,632.54	2.06
Regulatory Credits...	(4,043,516.06)	(1,456,907.44)	(2,586,608.62)	(177.54)
Taxes				
Federal Income..	17,526,242.14	31,011,267.25	(13,485,025.11)	(43.48)
State Income...	8,374,527.53	3,803,803.82	4,570,723.71	120.16
Deferred Federal Income - Net.................................	29,366,869.63	15,183,375.81	14,183,493.82	93.41
Deferred State Income - Net......................................	(846,709.80)	4,422,138.13	(5,268,847.93)	(119.15)
Property and Other..	18,362,646.14	15,964,778.90	2,397,867.24	15.02
Investment Tax Credit...	-	-	-	-
Amortization of Investment Tax Credit.....................	(1,861,605.00)	(1,667,850.00)	(193,755.00)	(11.62)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	1,748,510.59	1,339,789.42	408,721.17	30.51
Total Operating Expenses...	815,232,584.49	763,742,714.04	51,489,870.45	6.74
Net Operating Income..	120,212,439.99	122,969,904.58	(2,757,464.59)	(2.24)
Other Income Less Deductions.................................	384,959.15	(4,781,841.09)	5,166,800.24	108.05
Income Before Interest Charges................................	120,597,399.14	118,188,063.49	2,409,335.65	2.04
Interest on Long-Term Debt...	26,031,331.47	29,932,130.07	(3,900,798.60)	(13.03)
Amortization of Debt Expense - Net............................	2,212,230.69	931,471.00	1,280,759.69	137.50
Other Interest Expenses..	1,667,138.53	1,730,316.92	(63,178.39)	(3.65)
Total Interest Charges...	29,910,700.69	32,593,917.99	(2,683,217.30)	(8.23)
Net Income...	$ 90,686,698.45	$ 85,594,145.50	$ 5,092,552.95	5.95

September 22, 2011

Louisville Gas and Electric 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..	$ 1,047,974,421.20	$ 981,442,017.34	$ 66,532,403.86	6.78
Gas Operating Revenues...	319,316,907.51	285,049,580.23	34,267,327.28	12.02
Total Operating Revenues...	1,367,291,328.71	1,266,491,597.57	100,799,731.14	7.96
Fuel for Electric Generation...	367,085,506.52	343,639,244.64	23,446,261.88	6.82
Power Purchased..	66,842,840.35	55,457,164.17	11,385,676.18	20.53
Gas Supply Expenses...	177,749,235.78	162,624,642.09	15,124,593.69	9.30
Other Operation Expenses..	237,670,311.23	219,412,934.18	18,257,377.05	8.32
Maintenance..	125,046,479.56	63,917,957.02	61,128,522.54	95.64
Depreciation..	138,593,178.99	130,476,101.20	8,117,077.79	6.22
Amortization Expense...	7,834,621.44	8,025,026.36	(190,404.92)	(2.37)
Regulatory Credits..	(6,856,340.07)	(2,184,738.37)	(4,671,601.70)	(213.83)
Taxes				
Federal Income..	15,389,582.07	44,785,206.35	(29,395,624.28)	(65.64)
State Income...	10,617,891.14	4,955,147.86	5,662,743.28	114.28
Deferred Federal Income - Net.................................	41,850,498.82	19,978,380.07	21,872,118.75	109.48
Deferred State Income - Net......................................	(2,898,823.49)	6,633,874.30	(9,532,697.79)	(143.70)
Property and Other..	24,969,491.06	21,690,578.91	3,278,912.15	15.12
Investment Tax Credit...	-	1,824,673.02	(1,824,673.02)	(100.00)
Amortization of Investment Tax Credit.....................	(2,695,529.00)	(2,674,091.56)	(21,437.44)	(0.80)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	3,692,826.80	1,996,905.41	1,695,921.39	84.93
Total Operating Expenses...	1,204,889,193.26	1,080,524,545.51	124,364,647.75	11.51
Net Operating Income..	162,402,135.45	185,967,052.06	(23,564,916.61)	(12.67)
Other Income Less Deductions.................................	15,884,272.58	(3,340,567.33)	19,224,839.91	575.50
Income Before Interest Charges................................	178,286,408.03	182,626,484.73	(4,340,076.70)	(2.38)
Interest on Long-Term Debt...	39,994,248.57	44,070,710.34	(4,076,461.77)	(9.25)
Amortization of Debt Expense - Net............................	2,945,385.43	1,404,582.66	1,540,802.77	109.70
Other Interest Expenses..	2,539,835.36	2,723,707.54	(183,872.18)	(6.75)
Total Interest Charges...	45,479,469.36	48,199,000.54	(2,719,531.18)	(5.64)
Net Income..	$ 132,806,938.67	$ 134,427,484.19	$ (1,620,545.52)	(1.21)

September 22, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings
August 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period..	$ 865,073,836.64	$ 787,479,070.96	$ 827,993,251.96	$ 755,278,866.24	$ 810,873,011.74	$ 706,445,527.55
Add:						
Net Income for Period..	11,356,113.77	23,393,940.78	90,686,698.45	85,594,145.50	132,806,938.67	134,427,484.19
Deduct:						
Common Dividends						
Common Stock Without Par Value.....................	13,000,000.00	-	55,250,000.00	30,000,000.00	80,250,000.00	30,000,000.00
Balance at End of Period...	$ 863,429,950.41	$ 810,873,011.74	$ 863,429,950.41	$ 810,873,011.74	$ 863,429,950.41	$ 810,873,011.74

September 22, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of August 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,815,048,867.20	$ 4,606,776,233.47
Less: Reserves for Depreciation and Amortization	2,099,822,626.80	2,029,983,137.15
Total	2,715,226,240.40	2,576,793,096.32
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	26,739,003.13	20,609,773.64
Total	27,345,168.33	21,215,938.84
Current and Accrued Assets		
Cash	41,235,356.47	6,526,467.04
Special Deposits	2,204,705.90	694,352.78
Temporary Cash Investments	42,115,568.00	119.71
Accounts Receivable - Less Reserve	133,715,904.02	157,954,307.83
Accounts Receivable from Associated Companies	14,603,137.03	22,334,304.00
Materials and Supplies - At Average Cost		
Fuel	51,087,714.21	62,977,241.54
Plant Materials and Operating Supplies	30,417,147.49	29,209,716.40
Stores Expense	5,422,256.65	4,798,275.05
Gas Stored Underground	45,030,809.18	48,929,595.86
Emission Allowances	2,005.06	3,240.25
Prepayments	6,575,036.00	5,872,425.02
Miscellaneous Current and Accrued Assets	951,689.47	2,274,436.12
Total	373,361,329.48	341,574,481.60
Deferred Debits and Other		
Unamortized Debt Expense	13,117,553.69	3,729,929.61
Unamortized Loss on Bonds	21,126,625.85	22,338,661.25
Accumulated Deferred Income Taxes	56,272,700.06	52,250,170.26
Deferred Regulatory Assets	369,108,007.04	328,198,136.08
Other Deferred Debits	1,352,515.52	575,187.76
Total	460,977,402.16	407,092,084.96
Total Assets	$ 3,576,910,140.37	$ 3,346,675,601.72

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	(14,616,475.40)
Retained Earnings	863,429,950.41	810,873,011.74
Total Proprietary Capital	1,371,345,984.86	1,304,172,570.79
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds	531,238,255.78	-
LT Notes Payable to Associated Companies	-	485,000,000.00
Total Long-Term Debt	1,105,542,255.78	896,104,000.00
Total Capitalization	2,476,888,240.64	2,200,276,570.79
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	118,326,400.00
Accounts Payable	87,601,078.61	84,988,459.47
Accounts Payable to Associated Companies	17,443,956.77	18,509,327.38
Customer Deposits	22,667,140.95	24,270,260.87
Taxes Accrued	31,834,314.50	34,501,171.40
Interest Accrued	9,378,075.45	2,386,121.71
Dividends Declared	13,000,000.00	-
Miscellaneous Current and Accrued Liabilities	23,121,809.92	19,448,952.37
Total	205,046,376.20	302,430,693.20
Deferred Credits and Other		
Accumulated Deferred Income Taxes	504,554,359.26	442,364,833.95
Investment Tax Credit	43,662,971.13	46,358,500.13
Regulatory Liabilities	62,515,471.19	51,689,278.97
Customer Advances for Construction	8,059,948.10	8,623,967.39
Asset Retirement Obligations	52,443,159.11	34,383,418.56
Other Deferred Credits	26,770,314.68	26,842,521.07
Miscellaneous Long-Term Liabilities	51,419,138.37	56,538,247.45
Accum Provision for Postretirement Benefits	145,550,161.69	177,167,570.21
Total	894,975,523.53	843,968,337.73
Total Liabilities and Stockholders' Equity	$ 3,576,910,140.37	$ 3,346,675,601.72

September 22, 2011

Louisville Gas and Electric 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..	75,000,000	21,294,223	$ 425,170,424.09	
Less: Common Stock Expense..			835,888.64	
Paid-In Capital..			83,581,499.00	
Other Comprehensive Income..			-	
Retained Earnings..			863,429,950.41	
Total Proprietary Capital...			1,371,345,984.86	55.37
Long-Term Debt				
Pollution Control Bonds..				
Jefferson County 2000 Series A due 05/01/27 5.375%................			25,000,000.00	
Trimble County 2000 Series A due 08/01/30 Var%.....................			83,335,000.00	
Jefferson County 2001 Series A due 09/01/26 Var%..................			22,500,000.00	
Jefferson County 2001 Series A due 09/01/27 Var%...................			10,104,000.00	
Jefferson County 2001 Series B due 11/01/27 Var%..................			35,000,000.00	
Trimble County 2001 Series A due 09/01/26 Var%.....................			27,500,000.00	
Trimble County 2001 Series A due 10/01/32 Var%.....................			41,665,000.00	
Trimble County 2001 Series B due 11/01/27 Var%.....................			35,000,000.00	
Louisville Metro 2003 Series A due 10/01/33 1.900%.................			128,000,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%.................			40,000,000.00	
Louisville Metro 2007 Series A due 06/01/33 5.625%.................			31,000,000.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%.................			35,200,000.00	
Trimble County 2007 Series A due 06/01/33 4.600%..................			60,000,000.00	
Total Pollution Control Bonds..			574,304,000.00	23.19
First Mortgage Bonds...				
First Mortgage Bond Due 11/15/15 1.625%..................................			250,000,000.00	
First Mortgage Bond Due 11/15/40 5.125%..................................			285,000,000.00	
Total First Mortgage Bonds..			535,000,000.00	21.59
Less: First Mortgage Bonds Debt Discount.....................................				
First Mortgage Bond Due 11/15/15 1.625%..................................			(742,770.86)	
First Mortgage Bond Due 11/15/40 5.125%..................................			(3,018,973.36)	
			(3,761,744.22)	-0.15
Total First Mortgage Bonds - Net of Debt Discount........................			531,238,255.78	21.44
Total Capitalization..			$ 2,476,888,240.64	100.00

September 22, 2011

Louisville Gas and Electric Company
Summary Trial Balance
August 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 4,815,048,867.20	$ 4,815,048,867.20
Reserves for Depreciation and Amortization		(2,099,822,626.80)
Depreciation of Plant		
Electric	(1,757,945,496.73)	
Gas	(236,717,955.48)	
Common	(85,193,554.59)	
Amortization of Plant		
Common	(19,964,720.00)	
Gas	(800.00)	
Electric	(100.00)	
Investments		27,345,168.33
Special Funds	26,739,003.13	
Ohio Valley Electric Corporation	594,286.00	
Nonutility Property	11,879.20	
Cash	41,235,356.47	41,235,356.47
Special Deposits		2,204,705.90
MAN Margin Call	1,508,371.00	
Other Special Deposits	696,334.90	
Temporary Cash Investments	42,115,568.00	42,115,568.00
Accounts Receivable - Less Reserve		133,715,904.02
Customers - Active	69,484,414.94	
Unbilled Revenues	58,433,771.24	
IMPA	2,024,067.76	
IMEA	1,994,792.11	
Bechtel Liquidated Damages	1,480,290.00	
Sundry Accounts Receivable	1,148,152.52	
Transmission Sales	550,432.16	
Wholesale Sales	292,615.89	
Damage Claims	279,366.18	
IMEA/IMPA Net Portion of Bechtel Liquidated damages	(370,072.50)	
Other	338,365.15	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	4,181,094.82	
Accrual	(3,383,404.14)	
Reserve	(1,652,352.00)	
Recoveries	(798,866.56)	
A/R Miscellaneous	(286,763.55)	
Accounts Receivable from Associated Companies		14,603,137.03
LG&E - KU Energy Services/Kentucky Utilities	14,497,529.77	
PPL Energy Funding	105,607.26	
Fuel		51,087,714.21
Coal 1,082,469.03 Tons @ $46.77; MMBtu 24,749,501.81 @ 204.56¢	50,628,479.22	
Fuel Oil 163,137.76 Gallons @ 261.41¢	426,457.84	
Gas Pipeline 5,100 Mcf @ $6.43	32,777.15	
Plant Materials and Operating Supplies		30,417,147.49
Regular Materials and Supplies	29,963,564.89	
Limestone 52,053.43 Tons @ $8.71	453,582.60	
Stores Expense Undistributed	5,422,256.65	5,422,256.65
Gas Stored Underground - Current		45,030,809.18
Gas Stored Underground* 9,332,584 Mcf (14.73 psia) @ $4.83	45,030,809.18	
Emission Allowances	2,005.06	2,005.06

September 22, 2011

Louisville Gas and Electric Company
Summary Trial Balance
August 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Prepayments		$ 6,575,036.00
Insurance	3,158,854.02	
Taxes	1,628,866.06	
Rights of Way	226,666.71	
Risk Management and Workers Compensation	90,000.00	
Franchises	69,086.22	
Other	1,401,562.99	
Miscellaneous Current Assets		951,689.47
Derivative Asset - Non-Hedging	951,689.47	
Unamortized Debt Expense		13,117,553.69
Trimble County 2000 Series A due 08/01/30 Var%	732,214.48	
Jefferson County 2001 Series A due 09/01/26 Var%	148,856.58	
Jefferson County 2001 Series A due 09/01/27 Var%	326,279.92	
Jefferson County 2001 Series B due 11/01/27 Var%	177,756.54	
Trimble County 2001 Series A due 09/01/26 Var%	161,849.76	
Trimble County 2001 Series B due 11/01/27 Var%	177,785.70	
Trimble County 2002 Series A due 10/01/32 Var%	784,751.45	
Louisville Metro 2003 Series A Due 10/01/33 1.900%	433,045.82	
Louisville Metro 2007 Series B Due 06/01/33 1.900%	162,569.28	
Trimble County 2007 Series A due 06/01/33 4.600%	1,033,873.46	
First Mortgage Bond due 11/15/15 1.625%	2,141,887.85	
First Mortgage Bond due 11/15/40 5.125%	3,430,769.13	
Revolving Credit Agreement	3,405,913.72	
Unamortized Loss on Bonds	21,126,625.85	21,126,625.85
Accumulated Deferred Income Taxes		56,272,700.06
Federal		
Electric	41,137,768.00	
Gas	5,540,688.50	
State		
Electric	8,557,637.60	
Gas	1,036,605.96	
Regulatory Assets		369,108,007.04
Pension and Postretirement Benefits	213,180,670.00	
Interest Rate Swap Ineffectiveness	50,071,223.63	
2009 Winter Storm	39,089,232.13	
2008 Wind Storm	20,990,130.07	
Deferred Taxes - ASC 740		
Federal		
Electric	12,630,478.54	
State		
Electric	2,303,430.74	
Swap Termination	9,023,380.42	
Asset Retirement Obligations		
Electric	8,260,817.74	
Gas	659,208.34	
Common	6,460.84	
Gas Supply Clause/PBR	4,901,945.43	
Fuel Adjustment Clause	4,605,000.00	
MISO Exit Fee	1,009,577.50	
Rate Case Expenses	1,008,657.18	
KCCS Funding	640,237.87	
EKPC FERC Transmission Costs	423,930.96	
CMRG Funding	186,990.00	
General Management Audit	116,635.65	
Other Deferred Debits	1,352,515.52	1,352,515.52
Total Assets	$ 3,576,910,140.37	$ 3,576,910,140.37

* Excludes:

	$	Mcf
Non-recoverable Base Gas	9,648,855.00	7,880,000
Recoverable Base Gas	2,139,990.00	2,930,000
	11,788,845.00	10,810,000

September 22, 2011

Louisville Gas and Electric Company
Summary Trial Balance
August 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 1,371,345,984.86
Common Stock	425,170,424.09	
Less: Common Stock Expense	835,888.64	
Paid-In Capital	83,581,499.00	
Retained Earnings	863,429,950.41	
Pollution Control Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,238,255.78	531,238,255.78
Accounts Payable		87,601,078.61
Regular	85,352,935.99	
Salaries and Wages Accrued	2,197,660.61	
Employee Withholdings Payable	50,482.01	
Accounts Payable to Associated Companies		17,443,956.77
LG&E - KU Energy Services/Kentucky Utilities	17,443,956.77	
Customers' Deposits	22,667,140.95	22,667,140.95
Taxes Accrued	31,834,314.50	31,834,314.50
Interest Accrued		9,378,075.45
Jefferson County 2000 Series A due 05/01/27 5.375%	447,916.67	
Trimble County 2000 Series A due 08/01/30 Var%	6,250.13	
Jefferson County 2001 Series A due 09/01/26 Var%	4,832.88	
Jefferson County 2001 Series A due 09/01/27 Var%	78.59	
Jefferson County 2001 Series B due 11/01/27 Var%	3,722.46	
Trimble County 2001 Series A due 09/01/26 Var%	6,343.84	
Trimble County 2001 Series A due 10/01/32 Var%	5,171.03	
Trimble County 2001 Series B due 11/01/27 Var%	3,465.75	
Louisville Metro 2003 Series A due 10/01/33 1.900%	1,020,088.89	
Louisville Metro 2005 Series A due 02/01/35 5.750%	185,277.78	
Louisville Metro 2007 Series A due 06/01/33 5.625%	435,937.50	
Louisville Metro 2007 Series B due 06/01/33 1.900%	169,057.78	
Trimble County 2007 Series A due 06/01/33 4.600%	690,000.00	
Interest Rate Swaps	651,422.08	
First Mortgage Bond due 11/15/15 1.625%	1,196,180.56	
First Mortgage Bond due 11/15/40 5.125%	4,300,729.17	
Customers' Deposits	239,546.16	
Other	12,054.18	
Dividends Declared		13,000,000.00
Dividend Payable to LG&E and KU Energy LLC	13,000,000.00	
Miscellaneous Current and Accrued Liabilities		23,121,809.92
Vacation Pay Accrued	6,718,979.89	
Customer Overpayments	4,395,407.17	
ASC 815 Derivative Liability	3,879,983.23	
No-Notice Gas Payable	3,005,378.46	
Derivative Liabilities - Non-Hedging	1,662,701.14	
Tax Collections Payable	1,427,113.97	
Unearned Revenue	663,016.89	
Postretirement Benefits - Current	624,694.04	
Service Deposit Refund Payable	270,244.10	
Home Energy Assistance	352,020.37	
Other	122,270.66	

Louisville Gas and Electric Company
Summary Trial Balance
August 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Accumulated Deferred Income Taxes		$ 504,554,359.26
Federal		
Electric	358,574,191.20	
Gas	77,538,619.38	
State		
Electric	56,780,143.31	
Gas	11,661,405.37	
Investment Tax Credit		43,662,971.13
Advanced Coal Credit	23,349,913.00	
Job Development Credit		
Electric	19,711,747.98	
Gas	601,310.15	
Regulatory Liabilities		62,515,471.19
Deferred Taxes		
Federal		
Electric	41,796,049.40	
Gas	(11,563,922.74)	
State		
Electric	18,166,454.82	
Gas	(107,790.06)	
DSM Cost Recovery	6,844,908.07	
Gas Supply Clause/PBR	3,175,448.75	
Asset Retirement Obligations		
Gas	2,162,558.52	
Electric	268,569.00	
Environmental Cost Recovery	801,231.00	
MISO Schedule 10 Charges	532,439.18	
Purchased Gas Adjustment - Tennessee Gas	439,525.25	
Customers' Advances for Construction		8,059,948.10
Line Extensions		
Gas	6,506,239.39	
Electric	792,826.79	
Customer Advances - Museum Plaza	696,334.90	
Other	64,547.02	
Asset Retirement Obligations		52,443,159.11
Electric	34,973,997.69	
Gas	17,363,027.60	
Common	106,133.82	
Other Deferred Credits	26,770,314.68	26,770,314.68
Miscellaneous Long-Term Liabilities		51,419,138.37
Long-Term Derivative Liabilities - ASC 815	46,191,240.40	
Workers' Compensation	5,227,897.97	
Accumulated Provision for Benefits		145,550,161.69
Postretirement Benefits - ASC 715	80,420,620.01	
Pension Payable	61,662,688.50	
Post Employment Benefits Payable	3,698,041.00	
Post Employment Medicare Subsidy	(231,187.82)	
Total Liabilities and Stockholders' Equity	$ 3,576,910,140.37	$ 3,576,910,140.37

September 22, 2011

Louisville Gas and Electric Company
Statement of Cash Flows
August 31, 2011

	Year to Date	
	2011	2010
Cash Flows from Operating Activities		
Net income	$ 90,686,698.45	$ 85,594,145.50
Items not requiring (providing) cash currently:		
Depreciation	94,470,105.94	87,086,930.22
Amortization	5,320,130.98	5,212,498.44
Deferred income taxes - net	28,632,823.32	19,605,513.94
Investment tax credit - net	(1,861,605.00)	(1,667,850.00)
Gain on disposal of assets	(64,930.53)	(33,760.40)
Other	6,546,086.47	41,678,407.23
Change in receivables	37,772,807.07	(32,593,220.02)
Change in inventory	30,477,971.78	3,995,690.95
Change in allowance inventory	723.90	930.75
Change in payables and accrued expenses	44,948,884.65	(23,388,798.13)
Change in regulatory assets	(24,955,008.22)	(8,208,041.37)
Change in regulatory liabilities	11,089,122.73	(33,217,929.61)
Change in other deferred debits	(22,603,684.42)	(32,643.26)
Change in other deferred credits	21,169,954.84	18,860,035.39
Pension and postretirement funding	(67,940,500.00)	(24,267,900.00)
Other	(6,664,672.77)	(12,497,419.39)
Net cash provided (used) by operating activities	247,024,909.19	126,126,590.24
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(91,939,141.60)	(35,965,272.45)
Gross additions to common utility plant - construction expenditures	(5,019,316.90)	(7,044,224.75)
Proceeds received from sales of property	64,930.53	33,760.40
Change in restricted cash	(7,977,004.56)	-
Change in derivatives	-	280,813.69
Reissuance of reacquired bonds as Available for Sale debt securities	163,200,000.00	-
Other	(5,784,927.77)	-
Net cash provided (used) by investing activities	52,544,539.70	(42,694,923.11)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(1,218,536.26)	(26,566.76)
Net change in short-term debt	(174,876,000.00)	(52,074,000.00)
Dividends on common stock	(42,250,000.00)	(30,000,000.00)
Net cash provided (used) by financing activities	(218,344,536.26)	(82,100,566.76)
Net Increase (Decrease) in Cash and Cash Equivalents	81,224,912.63	1,331,100.37
Cash and Cash Equivalents at Beginning of Period	2,126,011.84	5,195,486.38
Cash and Cash Equivalents at End of Period	$ 83,350,924.47	$ 6,526,586.75

September 22, 2011

Louisville Gas and Electric 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						
Jefferson County 2000 Series A due 05/01/27 5.375%........................	$ 111,979.18	$ 111,979.17	$ 895,833.37	$ 895,833.24	$ 1,343,750.05	$ 1,343,749.92
Trimble County 2000 Series A due 08/01/30 Var%............................	9,213.15	30,498.30	135,592.93	268,246.10	258,627.79	346,303.18
Jefferson County 2001 Series A due 09/01/26 Var%..........................	1,437.01	3,866.17	15,150.25	31,423.43	30,861.95	38,844.44
Jefferson County 2001 Series A due 09/01/27 Var%..........................	5,480.15	19,109.60	141,065.76	108,924.67	221,048.64	174,113.03
Jefferson County 2001 Series B due 11/01/27 Var%..........................	12,954.24	40,229.86	213,357.28	242,117.47	327,744.94	360,494.18
Trimble County 2001 Series A due 09/01/26 Var%............................	6,607.54	13,750.01	69,269.88	115,703.44	118,581.51	198,429.48
Trimble County 2001 Series A due 10/01/32 Var%............................	8,093.29	21,338.19	88,802.36	227,856.56	155,912.69	263,596.01
Trimble County 2001 Series B due 11/01/27 Var%............................	12,897.26	40,254.77	210,670.94	243,302.66	323,917.50	361,679.35
Louisville Metro 2003 Series A due 10/01/33 1.900%........................	202,666.67	-	1,547,022.11	-	1,547,022.11	43,272.48
Louisville Metro 2005 Series A due 02/01/35 5.750%........................	191,666.67	191,666.67	1,533,333.32	1,533,333.23	2,300,000.00	2,299,999.91
Louisville Metro 2007 Series A due 06/01/33 5.625%........................	145,312.49	145,312.50	1,162,499.92	1,162,499.95	1,743,749.92	1,743,749.95
Louisville Metro 2007 Series B due 06/01/33 1.900%........................	55,733.34	-	425,431.14	-	425,431.14	-
Trimble County 2007 Series A due 06/01/33 4.600%..........................	230,000.00	230,000.00	1,840,000.00	1,840,000.00	2,760,000.00	2,760,000.00
Interest Rate Swaps..	651,422.07	678,250.50	5,122,463.87	5,501,689.30	7,319,114.88	7,494,678.36
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/15/15 1.625%...	338,541.67	-	2,708,333.33	-	3,216,145.84	-
First Mortgage Bond due 11/15/40 5.125%...	1,217,187.50	-	9,737,500.00	-	11,563,281.25	-
Fidelia/PPL...	-	2,220,149.99	-	17,761,200.02	5,559,375.01	26,641,800.05
Revolving Credit Agreement..	-	-	185,005.01	-	779,683.35	-
Total...	3,201,192.23	3,746,405.73	26,031,331.47	29,932,130.07	39,994,248.57	44,070,710.34
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense...	178,563.96	15,546.83	1,404,206.93	124,232.19	1,733,349.75	186,304.30
Amortization of Loss on Reacquired Debt..	101,002.97	101,002.98	808,023.76	807,238.81	1,212,035.68	1,218,278.36
Total...	279,566.93	116,549.81	2,212,230.69	931,471.00	2,945,385.43	1,404,582.66
Other Interest Charges						
Customers' Deposits..	115,137.50	108,831.84	929,418.96	926,621.72	1,391,703.70	1,556,409.57
Other Tax Deficiencies...	-	-	-	7,469.00	(24,969.00)	(7,411.00)
Interest on DSM Cost Recovery...	1,556.85	968.14	9,376.24	17,388.29	18,403.19	95,355.96
Interest on Debt to Associated Companies..	-	28,309.68	8,862.00	213,237.61	58,046.27	326,627.88
Other Interest Expense...	158,647.92	12,226.62	719,481.33	565,600.30	1,096,651.20	752,725.13
Total...	275,342.27	150,336.28	1,667,138.53	1,730,316.92	2,539,835.36	2,723,707.54
Total Interest...	$ 3,756,101.43	$ 4,013,291.82	$ 29,910,700.69	$ 32,593,917.99	$ 45,479,469.36	$ 48,199,000.54

September 22, 2011

Louisville Gas and Electric 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	$ 1,450,538.00	$ 1,222,746.10	$ 11,601,312.00	$ 9,780,735.48
Unemployment	4,249.22	3,532.50	118,274.70	128,591.15
FICA	688,506.75	577,611.86	5,317,374.20	4,735,849.40
Public Service Commission Fee	162,886.60	161,096.90	1,292,354.64	1,292,246.34
Federal Income	5,664,531.39	11,783,267.74	17,526,242.14	31,011,267.25
State Income	1,033,045.23	2,148,924.21	8,374,527.53	3,803,803.82
Miscellaneous	3,246.57	-	33,330.59	27,356.53
Total Charged to Operating Expense	9,007,003.76	15,897,179.31	44,263,415.80	50,779,849.97
Taxes Charged to Other Accounts	177,012.03	1,258,183.53	2,173,785.38	(748,142.83)
Taxes Accrued on Intercompany Accounts	(33,994.58)	(234,840.52)	(1,794,682.33)	(1,935,004.17)
Total Taxes Charged	$ 9,150,021.21	$ 16,920,522.32	$ 44,642,518.85	$ 48,096,702.97

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	$ 11,354,131.66	$ 11,712,269.25	$ 11,553,636.73	$ 11,512,764.18
Unemployment	54,386.05	87,992.71	141,918.21	460.55
FICA	590,648.24	4,355,526.88	4,452,095.62	494,079.50
Federal Income	(3,741,320.05)	17,434,191.06	(2,438,136.00)	16,131,007.01
State Income	229,108.93	8,357,740.12	5,155,166.44	3,431,682.61
Kentucky Sales and Use Tax	1,088,857.95	2,591,197.96	3,433,011.87	247,044.04
Miscellaneous	22,339.97	103,600.87	108,664.23	17,276.61
Totals	$ 9,598,152.75	$ 44,642,518.85	$ 22,406,357.11	$ 31,834,314.50

September 22, 2011

Louisville Gas and Electric Company
Summary of Utility Plant
August 31, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant In Service**						
Common						
Common General Plant	$ 159,884,459.36	$ 9,268,027.56	$ (663,361.41)	$ -	$ 8,604,666.15	$ 168,489,125.51
Common Intangible Plant	56,455,326.72	7,946,903.92	(1,661,801.58)	-	6,285,102.34	62,740,429.06
	216,339,786.08	17,214,931.48	(2,325,162.99)	-	14,889,768.49	231,229,554.57
Electric						
Electric Distribution	927,289,038.50	29,937,916.12	(5,858,028.15)	47,153.43	24,127,041.40	951,416,079.90
Electric General Plant	16,521,615.59	1,289,339.27	(1,934,885.80)	-	(645,546.53)	15,876,069.06
Electric Hydro Production	41,680,209.14	910,668.82	(229,891.00)	-	680,777.82	42,360,986.96
Electric Intangible Plant	2,340.29	-	-	-	-	2,340.29
Electric Other Production	229,401,033.01	1,720,153.61	(876,137.26)	38,429.14	882,445.49	230,283,478.50
Electric Steam Production	1,930,347,044.43	200,202,638.37	(22,890,899.84)	4,144,130.56	181,455,869.09	2,111,802,913.52
Electric Transmission	247,742,496.14	5,498,112.46	(1,090,587.06)	(47,153.43)	4,360,371.97	252,102,868.11
	3,392,983,777.10	239,558,828.65	(32,880,429.11)	4,182,559.70	210,860,959.24	3,603,844,736.34
Gas						
Gas Distribution	549,799,120.70	34,872,795.04	(585,227.95)	97,729.20	34,385,296.29	584,184,416.99
Gas General Plant	9,178,093.57	400,882.53	(995,401.23)	(97,729.20)	(692,247.90)	8,485,845.67
Gas Intangible Plant	1,187.49	-	-	-	-	1,187.49
Gas Storage	78,415,311.06	2,093,712.47	(1,418,787.23)	-	674,925.24	79,090,236.30
Gas Transmission	16,661,869.68	320,510.93	(15,069.35)	-	305,441.58	16,967,311.26
	654,055,582.50	37,687,900.97	(3,014,485.76)	-	34,673,415.21	688,728,997.71
Total 101 Accounts	4,263,379,145.68	294,461,661.10	(38,220,077.86)	4,182,559.70	260,424,142.94	4,523,803,288.62
105 **Plant Held For Future Use**						
Electric						
Electric Distribution	649,014.48	-	-	-	-	649,014.48
Electric Steam Production	4,182,559.70	-	-	(4,182,559.70)	(4,182,559.70)	-
	4,831,574.18	-	-	(4,182,559.70)	(4,182,559.70)	649,014.48
Total 105001	$ 4,831,574.18	$ -	$ -	$ (4,182,559.70)	$ (4,182,559.70)	$ 649,014.48

Louisville Gas and Electric Company
Summary of Utility Plant
August 31, 2011

		Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
106	**Completed Construction Not Classified**						
	Common						
	Common General Plant..	$ 597,158.63	$ 41,790.50	$ -	$ -	$ 41,790.50	$ 638,949.13
	Common Intangible Plant......................................	2,714,931.36	(1,880,972.17)	-	-	(1,880,972.17)	833,959.19
		3,312,089.99	(1,839,181.67)	-	-	(1,839,181.67)	1,472,908.32
	Electric						
	Electric Distribution...	11,544,733.90	4,103,221.75	-	-	4,103,221.75	15,647,955.65
	Electric General Plant..	50,763.87	(50,763.87)	-	-	(50,763.87)	-
	Electric Hydro Production.....................................	16,952.26	174,504.11	-	-	174,504.11	191,456.37
	Electric Intangible Plant...	-	-	-	-	-	-
	Electric Other Production......................................	1,767,208.21	653,034.83	-	-	653,034.83	2,420,243.04
	Electric Steam Production......................................	15,929,229.77	8,838,831.03	-	-	8,838,831.03	24,768,060.80
	Electric Transmission...	35,045,472.82	1,467,689.72	-	-	1,467,689.72	36,513,162.54
		64,354,360.83	15,186,517.57	-	-	15,186,517.57	79,540,878.40
	Gas						
	Gas Distribution...	24,420,156.16	(6,784,158.88)	-	-	(6,784,158.88)	17,635,997.28
	Gas General Plant..	126,992.17	74,776.30	-	-	74,776.30	201,768.47
	Gas Intangible Plant...	-	-	-	-	-	-
	Gas Storage..	951,426.06	(34,213.10)	-	-	(34,213.10)	917,212.96
	Gas Transmission...	-	1,819,433.26	-	-	1,819,433.26	1,819,433.26
		25,498,574.39	(4,924,162.42)	-	-	(4,924,162.42)	20,574,411.97
	Total 106 Accounts....................................	93,165,025.21	8,423,173.48	-	-	8,423,173.48	101,588,198.69
117	**Gas Stored Underground-Noncurrent**						
	Gas						
	Gas Stored Nonrecoverable...................................	2,139,990.00	-	-	-	-	2,139,990.00
		2,139,990.00	-	-	-	-	2,139,990.00
	Total 117001..	2,139,990.00	-	-	-	-	2,139,990.00
121	**Nonutility Property**						
	Common						
	Non Utility Property..	75,239.56	-	-	-	-	75,239.56
		75,239.56	-	-	-	-	75,239.56
	Total 121001..	75,239.56	-	-	-	-	75,239.56
107	**Construction Work In Progress**						
	Common..	21,243,879.89	(10,356,432.91)	-	-	(10,356,432.91)	10,887,446.98
	Electric..	324,323,732.14	(183,280,799.71)	-	-	(183,280,799.71)	141,042,932.43
	Gas...	39,756,306.91	(4,818,310.91)	-	-	(4,818,310.91)	34,937,996.00
		385,323,918.94	(198,455,543.53)	-	-	(198,455,543.53)	186,868,375.41
	Total Plant (Non-CWIP).......................................	4,363,590,974.63	302,884,834.58	(38,220,077.86)	-	264,664,756.72	4,628,255,731.35
	Total Plant + CWIP...	4,748,914,893.57	104,429,291.05	(38,220,077.86)	-	66,209,213.19	4,815,124,106.76
	Total Plant + CWIP - Non Utility..............................	$ 4,748,839,654.01	$ 104,429,291.05	$ (38,220,077.86)	$ -	$ 66,209,213.19	$ 4,815,048,867.20

September 22, 2011

Louisville Gas and Electric 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										
Common General Plant...	$ (77,263,235.10)	$ (8,488,741.34)	$ 663,361.41	$ -	$ -	$ -	$ -	$ -	$ -	$ (85,088,615.03)
Common General Plant - ARO..	(343.19)	(1,373.60)	-	-	-	-	-	-	-	(1,716.79)
Electric Distribution...	(277,000,365.75)	(11,546,540.57)	5,858,028.15	(382.60)	-	-	-	-	-	(282,689,260.77)
Electric Distribution - ARO...	(1,256.54)	(4,022.57)	-	-	-	-	-	-	-	(5,279.11)
Electric General Plant..	(12,910,034.19)	(260,698.59)	1,934,885.80	-	-	-	-	-	-	(11,235,846.98)
Electric Hydro Production...	(9,718,276.66)	(374,599.11)	229,891.00	-	-	-	-	-	-	(9,862,984.77)
Electric Hydro Production - ARO..	(364.10)	(1,165.68)	-	-	-	-	-	-	-	(1,529.78)
Electric Other Production..	(60,282,055.17)	(5,455,064.14)	876,137.26	-	-	-	-	-	-	(64,860,982.05)
Electric Other Production - ARO...	(192.68)	(723.90)	-	-	-	-	-	-	-	(916.58)
Electric Steam Production...	(1,029,518,070.37)	(37,821,027.37)	22,215,223.48	-	-	-	-	-	-	(1,045,123,874.26)
Electric Steam Production - ARO..	(204,061.94)	(1,474,825.25)	675,676.36	-	-	-	-	-	-	(1,003,210.83)
Electric Transmission..	(119,192,606.75)	(2,918,880.23)	1,090,587.06	382.60	-	-	-	-	-	(121,020,517.32)
Electric Transmission - ARO...	(41.40)	(132.56)	-	-	-	-	-	-	-	(173.96)
Gas Distribution...	(125,049,477.23)	(7,668,433.04)	510,188.68	(13,332.40)	-	-	-	-	-	(132,221,053.99)
Gas Distribution - ARO...	(49,734.93)	(272,665.11)	75,039.27	-	-	-	-	-	-	(247,360.77)
Gas General Plant..	(6,299,629.20)	(207,289.10)	995,401.23	13,332.40	-	-	-	-	-	(5,498,184.67)
Gas Storage...	(31,288,281.49)	(720,370.12)	1,023,381.77	-	-	-	-	-	-	(30,985,269.84)
Gas Storage - ARO..	(39,466.10)	(540,096.80)	395,405.46	-	-	-	-	-	-	(184,157.44)
Gas Stored Nonrecoverable...	-	-	-	-	-	-	-	-	-	-
Gas Transmission..	(9,448,605.32)	(37,868.66)	15,069.35	-	-	-	-	-	-	(9,471,404.63)
Non Utility Property...	(63,360.36)	-	-	-	-	-	-	-	-	(63,360.36)
	(1,758,329,458.47)	(77,794,517.74)	36,558,276.28	-	-	-	-	-	-	(1,799,565,699.93)
Cost Of Removal										
Common General Plant...	(688,372.47)	(186,476.00)	-	-	-	-	332,962.76	-	-	(541,885.71)
Electric Distribution...	(146,715,298.78)	(4,573,310.08)	-	(55.48)	-	-	3,544,892.90	-	-	(147,743,771.44)
Electric General Plant..	3,866.64	-	-	-	-	-	-	-	-	3,866.64
Electric Hydro Production...	736,907.70	(28,442.81)	-	-	-	-	38,351.42	-	-	746,816.31
Electric Other Production..	(2,505,175.99)	(234,209.62)	-	-	-	-	104,342.09	-	-	(2,635,043.52)
Electric Steam Production...	(94,783,295.15)	(11,303,817.10)	-	-	-	-	2,481,619.86	-	-	(103,605,492.39)
Electric Transmission..	(24,538,454.78)	(939,455.74)	-	55.48	-	-	61,473.84	-	-	(25,416,381.20)
Gas Distribution...	(60,212,131.14)	(2,164,865.59)	-	-	-	-	1,480,225.35	-	-	(60,896,771.38)
Gas General Plant..	(0.02)	-	-	-	-	-	-	-	-	(0.02)
Gas Storage...	(170,437.90)	(73,953.49)	-	-	-	-	565,052.30	-	-	320,660.91
Gas Stored Nonrecoverable...	-	-	-	-	-	-	-	-	-	-
Gas Transmission..	(3,016,813.95)	(9,367.87)	-	-	-	-	42,869.45	-	-	(2,983,312.37)
Non Utility Property...	-	-	-	-	-	-	-	-	-	-
	$ (331,889,205.84)	$ (19,513,898.30)	$ -	$ -	$ -	$ -	$ 8,651,789.97	$ -	$ -	$ (342,751,314.17)

September 22, 2011

Louisville Gas and Electric 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
Salvage										
Common General Plant	$ 278,074.55	$ 255.52	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 278,330.07
Electric Distribution	17,535,024.98	926,527.44	-	-	-	-	-	(197,553.22)	-	18,263,999.20
Electric General Plant	138,281.25	1,540.40	-	-	-	-	-	-	-	139,821.65
Electric Hydro Production	376,638.17	-	-	-	-	-	-	-	-	376,638.17
Electric Other Production	(18,998.67)	-	-	-	-	-	-	-	-	(18,998.67)
Electric Steam Production	22,028,570.14	1,346,419.96	-	-	-	-	-	(34,636.38)	-	23,340,353.72
Electric Transmission	6,247,368.67	174,128.14	-	-	-	-	-	-	-	6,421,496.81
Gas Distribution	3,594,440.75	132,292.22	-	-	-	-	-	-	-	3,726,732.97
Gas General Plant	225,788.37	1,492.75	-	-	-	-	-	-	-	227,281.12
Gas Storage	269,933.04	11,434.24	-	-	-	-	-	-	-	281,367.28
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	217,923.11	3,512.95	-	-	-	-	-	-	-	221,436.06
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	50,893,044.36	2,597,603.62	-	-	-	-	-	(232,189.60)	-	53,258,458.38
Total Reserves										
Common	(77,737,236.57)	(8,676,335.42)	663,361.41	-	-	-	332,962.76	-	-	(85,417,247.82)
Electric	(1,730,321,891.37)	(74,488,299.38)	32,880,429.11	-	-	-	6,230,680.11	(232,189.60)	-	(1,765,931,271.13)
Gas	(231,266,492.01)	(11,546,177.62)	3,014,485.76	-	-	-	2,088,147.10	-	-	(237,710,036.77)
	(2,039,325,619.95)	(94,710,812.42)	36,558,276.28	-	-	-	8,651,789.97	(232,189.60)	-	(2,089,058,555.72)
Retirement Work In Progress										
Common	342,947.00	-	-	162,020.85	-	(332,962.76)	7,076.86	(20,894.00)	2,144.92	160,332.87
Electric	9,603,653.21	-	-	(35,892.93)	(909,868.03)	(5,656,867.72)	5,505,375.44	(430,136.64)	(90,488.93)	7,985,774.40
Gas	2,523,160.64	-	-	(66,835.06)	(1,053,809.06)	(1,292,343.38)	889,284.31	(4,846.40)	(2,529.76)	992,081.29
	12,469,760.85	-	-	59,292.86	(1,963,677.09)	(7,282,173.86)	6,401,736.61	(455,877.04)	(90,873.77)	9,138,188.56
YTD ACTIVITY	(2,026,855,859.10)	(94,710,812.42)	36,558,276.28	59,292.86	(1,963,677.09)	(7,282,173.86)	15,053,526.58	(688,066.64)	(90,873.77)	(2,079,920,367.16)
Amortization										
Common	(16,306,390.60)	(5,320,130.98)	1,661,801.58	-	-	-	-	-	-	(19,964,720.00)
Electric	(100.00)	-	-	-	-	-	-	-	-	(100.00)
Gas	(800.00)	-	-	-	-	-	-	-	-	(800.00)
AMORTIZATION TOTAL	(16,307,290.60)	(5,320,130.98)	1,661,801.58	-	-	-	-	-	-	(19,965,620.00)
Depreciation & Amortization Total	$ (2,043,163,149.70)	$ (100,030,943.40)	$ 38,220,077.86	$ 59,292.86	$ (1,963,677.09)	$ (7,282,173.86)	$ 15,053,526.58	$ (688,066.64)	$ (90,873.77)	$ (2,099,885,987.16)
Depr & Amort - Nonutility for Balance Sheet										(2,099,822,626.80)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)	$ 2,705,739,864.67									$ 2,715,226,240.40

September 22, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
August 31, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues.......................................	$ 105,479,442.77	$ -	$ 105,479,442.77
Gas Operating Revenues...	11,482,287.79	-	11,482,287.79
Total Operating Revenues..	116,961,730.56	-	116,961,730.56
Fuel for Electric Generation..	34,727,105.86	-	34,727,105.86
Power Purchased...	5,404,608.23	-	5,404,608.23
Gas Supply Expenses..	4,257,401.19	-	4,257,401.19
Other Operation Expenses...	21,424,773.59	-	21,424,773.59
Maintenance..	15,528,306.75	-	15,528,306.75
Depreciation..	11,790,920.26	-	11,790,920.26
Amortization Expense...	689,697.43	-	689,697.43
Regulatory Credits...	(360,697.95)	-	(360,697.95)
Taxes			
Federal Income...	5,664,531.39	-	5,664,531.39
State Income..	1,033,045.23	-	1,033,045.23
Deferred Federal Income - Net.................................	258,724.10	8,230.80	266,954.90
Deferred State Income - Net.....................................	(624,726.66)	1,501.06	(623,225.60)
Property and Other...	2,309,427.14	-	2,309,427.14
Amortization of Investment Tax Credit....................	(236,034.00)	-	(236,034.00)
Loss (Gain) from Disposition of Allowances...............	-	-	-
Accretion Expense..	216,401.98	-	216,401.98
Total Operating Expenses..	102,083,484.54	9,731.86	102,093,216.40
Net Operating Income...	14,878,246.02	(9,731.86)	14,868,514.16
Other Income Less Deductions.................................	233,969.18	-	233,969.18
Income Before Interest Charges................................	15,112,215.20	(9,731.86)	15,102,483.34
Interest on Long-Term Debt..	3,201,192.23	(25,017.63)	3,176,174.60
Amortization of Debt Expense - Net...........................	279,566.93	-	279,566.93
Other Interest Expenses...	275,342.27	-	275,342.27
Total Interest Charges..	3,756,101.43	(25,017.63)	3,731,083.80
Net Income..	$ 11,356,113.77	$ 15,285.77	$ 11,371,399.54

Note: Purchase accounting is subject to change through October 31, 2011

September 22, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
August 31, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues..	$ 729,565,952.64	$ -	$ 729,565,952.64
Gas Operating Revenues..	205,879,071.84	-	205,879,071.84
Total Operating Revenues...	935,445,024.48	-	935,445,024.48
Fuel for Electric Generation...	243,748,699.11	-	243,748,699.11
Power Purchased..	49,754,328.93	-	49,754,328.93
Gas Supply Expenses...	112,511,796.99	-	112,511,796.99
Other Operation Expenses...	158,474,724.89	27,884.66	158,502,609.55
Maintenance...	82,328,410.42	-	82,328,410.42
Depreciation..	94,470,105.94	-	94,470,105.94
Amortization Expense..	5,320,130.98	-	5,320,130.98
Regulatory Credits...	(4,043,516.06)	-	(4,043,516.06)
Taxes			
Federal Income..	17,526,242.14	-	17,526,242.14
State Income...	8,374,527.53	-	8,374,527.53
Deferred Federal Income - Net..................................	29,366,869.63	56,672.37	29,423,542.00
Deferred State Income - Net.....................................	(846,709.80)	10,335.41	(836,374.39)
Property and Other..	18,362,646.14	-	18,362,646.14
Amortization of Investment Tax Credit.....................	(1,861,605.00)	-	(1,861,605.00)
Loss (Gain) from Disposition of Allowances................	(2,577.94)	-	(2,577.94)
Accretion Expense...	1,748,510.59	-	1,748,510.59
Total Operating Expenses...	815,232,584.49	94,892.44	815,327,476.93
Net Operating Income..	120,212,439.99	(94,892.44)	120,117,547.55
Other Income Less Deductions.................................	384,959.15	-	384,959.15
Income Before Interest Charges................................	120,597,399.14	(94,892.44)	120,502,506.70
Interest on Long-Term Debt...	26,031,331.47	(200,141.04)	25,831,190.43
Amortization of Debt Expense - Net............................	2,212,230.69	-	2,212,230.69
Other Interest Expenses...	1,667,138.53	-	1,667,138.53
Total Interest Charges...	29,910,700.69	(200,141.04)	29,710,559.65
Net Income...	$ 90,686,698.45	$ 105,248.60	$ 90,791,947.05

Note: Purchase accounting is subject to change through October 31, 2011

September 22, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
August 31, 2011

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period………………………………	$ 865,073,836.64	$ 787,479,070.96	$ (808,809,319.61)	$ -	$ 56,264,517.03	$ 787,479,070.96
Add:						
Net Income (Loss) for Period…………………………	11,356,113.77	23,393,940.78	15,285.77	-	11,371,399.54	23,393,940.78
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	13,000,000.00	-	-	-	13,000,000.00	-
Balance at End of Period…………………………………	$ 863,429,950.41	$ 810,873,011.74	$ (808,794,033.84)	$ -	$ 54,635,916.57	$ 810,873,011.74

Note: Purchase accounting is subject to change through October 31, 2011

September 22, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
August 31, 2011

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……………………………	$ 827,993,251.96	$ 755,278,866.24	$ (808,899,282.44)	$ -	$ 19,093,969.52	$ 755,278,866.24
Add:						
Net Income (Loss) for Period…………………………	90,686,698.45	85,594,145.50	105,248.60	-	90,791,947.05	85,594,145.50
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	55,250,000.00	30,000,000.00	-	-	55,250,000.00	30,000,000.00
Balance at End of Period……………………………………	$ 863,429,950.41	$ 810,873,011.74	$ (808,794,033.84)	$ -	$ 54,635,916.57	$ 810,873,011.74

Note: Purchase accounting is subject to change through October 31, 2011

September 22, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
August 31, 2011

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period................................	$ 810,873,011.74	$ 706,445,527.55	$ -	$ -	$ 810,873,011.74	$ 706,445,527.55
Add:						
Net Income (Loss) for Period.............................	132,806,938.67	134,427,484.19	152,857.68	-	132,959,796.35	134,427,484.19
Deduct:						
Adjustment to Retained Earnings........................	-	-	808,946,891.52	-	808,946,891.52	-
Common Dividends						
Common Stock Without Par Value.................	80,250,000.00	30,000,000.00	-	-	80,250,000.00	30,000,000.00
Balance at End of Period.......................................	$ 863,429,950.41	$ 810,873,011.74	$ (808,794,033.84)	$ -	$ 54,635,916.57	$ 810,873,011.74

Note: Purchase accounting is subject to change through October 31, 2011

September 22, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of August 31, 2011

Assets	Without Purchase Accounting	Purchase Accounting	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 4,815,048,867.20	$ -	$ 4,815,048,867.20
Less: Reserves for Depreciation and Amortization....	2,099,822,626.80	-	2,099,822,626.80
Total..	2,715,226,240.40	-	2,715,226,240.40
Investments			
Ohio Valley Electric Corporation.............................	594,286.00	-	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	-	11,879.20
Special Funds...	26,739,003.13	-	26,739,003.13
Total..	27,345,168.33	-	27,345,168.33
Current and Accrued Assets			
Cash..	41,235,356.47	-	41,235,356.47
Special Deposits..	2,204,705.90	-	2,204,705.90
Temporary Cash Investments...................................	42,115,568.00	-	42,115,568.00
Accounts Receivable - Less Reserve.........................	133,715,904.02	-	133,715,904.02
Accounts Receivable from Associated Companies....	14,603,137.03	-	14,603,137.03
Materials and Supplies - At Average Cost			
Fuel..	51,087,714.21	-	51,087,714.21
Plant Materials and Operating Supplies.................	30,417,147.49	-	30,417,147.49
Stores Expense...	5,422,256.65	-	5,422,256.65
Gas Stored Underground.......................................	45,030,809.18	-	45,030,809.18
Emission Allowances...	2,005.06	-	2,005.06
Prepayments..	6,575,036.00	-	6,575,036.00
Miscellaneous Current and Accrued Assets..............	951,689.47	-	951,689.47
Total..	373,361,329.48	-	373,361,329.48
Deferred Debits and Other			
Unamortized Debt Expense......................................	13,117,553.69	(3,543,367.89)	9,574,185.80
Unamortized Loss on Bonds....................................	21,126,625.85	-	21,126,625.85
Accumulated Deferred Income Taxes.......................	56,272,700.06	77,778,242.30	134,050,942.36
Deferred Regulatory Assets.....................................	369,108,007.04	10,558,566.68	379,666,573.72
Other Deferred Debits..	1,352,515.52	177,373,918.74	178,726,434.26
Goodwill..	-	389,157,351.59	389,157,351.59
Total..	460,977,402.16	651,324,711.42	1,112,302,113.58
Total Assets..	$ 3,576,910,140.37	$ 651,324,711.42	$ 4,228,234,851.79

Note: Purchase accounting is subject to change through October 31, 2011

September 22, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of August 31, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting	Total
Proprietary Capital			
Common Stock..	$ 425,170,424.09	$ -	$ 425,170,424.09
Less: Common Stock Expense......................................	835,888.64	-	835,888.64
Paid-In Capital...	83,581,499.00	1,194,085,869.02	1,277,667,368.02
Other Comprehensive Income......................................	-	-	-
Retained Earnings..	863,429,950.41	(808,794,033.84)	54,635,916.57
Total Proprietary Capital...	1,371,345,984.86	385,291,835.18	1,756,637,820.04
Pollution Control Bonds - Net of Reacquired Bonds....	574,304,000.00	6,326,540.70	580,630,540.70
First Mortgage Bonds..	531,238,255.78	-	531,238,255.78
LT Notes Payable to Associated Companies................	-	-	-
Total Long-Term Debt...	1,105,542,255.78	6,326,540.70	1,111,868,796.48
Total Capitalization..	2,476,888,240.64	391,618,375.88	2,868,506,616.52
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Accounts Payable..	87,601,078.61	-	87,601,078.61
Accounts Payable to Associated Companies................	17,443,956.77	-	17,443,956.77
Customer Deposits..	22,667,140.95	-	22,667,140.95
Taxes Accrued..	31,834,314.50	-	31,834,314.50
Dividends Declared..	13,000,000.00	-	13,000,000.00
Interest Accrued..	9,378,075.45	-	9,378,075.45
Miscellaneous Current and Accrued Liabilities...........	23,121,809.92	-	23,121,809.92
Total..	205,046,376.20	-	205,046,376.20
Deferred Credits and Other			
Accumulated Deferred Income Taxes..........................	504,554,359.26	75,317,218.01	579,871,577.27
Investment Tax Credit..	43,662,971.13	-	43,662,971.13
Regulatory Liabilities...	62,515,471.19	177,373,918.74	239,889,389.93
Customer Advances for Construction...........................	8,059,948.10	-	8,059,948.10
Asset Retirement Obligations.......................................	52,443,159.11	-	52,443,159.11
Other Deferred Credits...	26,770,314.68	7,015,198.79	33,785,513.47
Miscellaneous Long-Term Liabilities...........................	51,419,138.37	-	51,419,138.37
Misc Long-Term Liab Due to Assoc Cos......................	-	-	-
Accum Provision for Postretirement Benefits..............	145,550,161.69	-	145,550,161.69
Total..	894,975,523.53	259,706,335.54	1,154,681,859.07
Total Liabilities and Stockholders' Equity.........................	$ 3,576,910,140.37	$ 651,324,711.42	$ 4,228,234,851.79

Note: Purchase accounting is subject to change through October 31, 2011

September 22, 2011

LOUISVILLE GAS AND ELECTRIC COMPANY

Financial Reports

July 31, 2011

Index
Financial and Operating Reports

Louisville Gas and Electric 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.

Louisville Gas and Electric Company
Comparative Statement of Income
July 31, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 115,642,800.22	$ 104,164,227.85	$ 11,478,572.37	11.02
Gas Operating Revenues..	11,094,275.90	9,506,525.50	1,587,750.40	16.70
Total Operating Revenues...	126,737,076.12	113,670,753.35	13,066,322.77	11.49
Fuel for Electric Generation...	36,648,656.50	36,042,022.21	606,634.29	1.68
Power Purchased..	6,917,723.12	3,877,589.54	3,040,133.58	78.40
Gas Supply Expenses...	4,139,144.22	3,703,158.72	435,985.50	11.77
Other Operation Expenses..	20,283,093.61	18,452,230.68	1,830,862.93	9.92
Maintenance..	8,077,456.56	7,665,244.08	412,212.48	5.38
Depreciation..	11,822,081.46	10,982,619.64	839,461.82	7.64
Amortization Expense...	689,686.28	621,652.08	68,034.20	10.94
Regulatory Credits..	(386,874.71)	(184,204.73)	(202,669.98)	(110.02)
Taxes				
Federal Income..	10,655,071.01	8,612,458.61	2,042,612.40	23.72
State Income...	1,943,174.04	1,570,661.15	372,512.89	23.72
Deferred Federal Income - Net................................	-	(3.75)	3.75	100.00
Deferred State Income - Net......................................	-	-	-	-
Property and Other..	2,210,009.66	1,953,905.64	256,104.02	13.11
Investment Tax Credit...	-	-	-	-
Amortization of Investment Tax Credit.....................	(236,034.00)	(208,481.00)	(27,553.00)	(13.22)
Loss (Gain) from Disposition of Allowances...............	-	-	-	-
Accretion Expense..	215,963.40	169,564.97	46,398.43	27.36
Total Operating Expenses...	102,979,151.15	93,258,417.84	9,720,733.31	10.42
Net Operating Income..	23,757,924.97	20,412,335.51	3,345,589.46	16.39
Other Income Less Deductions.................................	217,199.43	(528,782.93)	745,982.36	141.08
Income Before Interest Charges................................	23,975,124.40	19,883,552.58	4,091,571.82	20.58
Interest on Long-Term Debt...	3,224,464.04	3,798,734.35	(574,270.31)	(15.12)
Amortization of Debt Expense - Net............................	279,566.93	116,549.81	163,017.12	139.87
Other Interest Expenses..	229,571.96	293,769.64	(64,197.68)	(21.85)
Total Interest Charges...	3,733,602.93	4,209,053.80	(475,450.87)	(11.30)
Net Income..	$ 20,241,521.47	$ 15,674,498.78	$ 4,567,022.69	29.14

August 19, 2011

Louisville Gas and Electric Company
Comparative Statement of Income
July 31, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 624,086,509.87	$ 581,670,725.48	$ 42,415,784.39	7.29
Gas Operating Revenues	194,396,784.05	178,913,700.72	15,483,083.33	8.65
Total Operating Revenues	818,483,293.92	760,584,426.20	57,898,867.72	7.61
Fuel for Electric Generation	209,021,593.25	209,297,729.59	(276,136.34)	(0.13)
Power Purchased	44,349,720.70	33,201,703.79	11,148,016.91	33.58
Gas Supply Expenses	108,254,395.80	99,625,272.14	8,629,123.66	8.66
Other Operation Expenses	137,049,951.30	126,608,123.52	10,441,827.78	8.25
Maintenance	66,800,103.67	61,464,409.03	5,335,694.64	8.68
Depreciation	82,679,185.68	76,040,903.89	6,638,281.79	8.73
Amortization Expense	4,630,433.55	4,589,717.80	40,715.75	0.89
Regulatory Credits	(3,682,818.11)	(1,271,854.40)	(2,410,963.71)	(189.56)
Taxes				
Federal Income	11,861,710.75	19,227,999.51	(7,366,288.76)	(38.31)
State Income	7,341,482.30	1,654,879.61	5,686,602.69	343.63
Deferred Federal Income - Net	29,108,145.53	15,183,375.81	13,924,769.72	91.71
Deferred State Income - Net	(221,983.14)	4,422,138.13	(4,644,121.27)	(105.02)
Property and Other	16,053,219.00	13,999,791.54	2,053,427.46	14.67
Investment Tax Credit	-	-	-	-
Amortization of Investment Tax Credit	(1,625,571.00)	(1,459,369.00)	(166,202.00)	(11.39)
Loss (Gain) from Disposition of Allowances	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense	1,532,108.61	1,169,376.14	362,732.47	31.02
Total Operating Expenses	713,149,099.95	663,719,736.96	49,429,362.99	7.45
Net Operating Income	105,334,193.97	96,864,689.24	8,469,504.73	8.74
Other Income Less Deductions	150,989.97	(6,083,858.35)	6,234,848.32	102.48
Income Before Interest Charges	105,485,183.94	90,780,830.89	14,704,353.05	16.20
Interest on Long-Term Debt	22,830,139.24	26,185,724.34	(3,355,585.10)	(12.81)
Amortization of Debt Expense - Net	1,932,663.76	814,921.19	1,117,742.57	137.16
Other Interest Expenses	1,391,796.26	1,579,980.64	(188,184.38)	(11.91)
Total Interest Charges	26,154,599.26	28,580,626.17	(2,426,026.91)	(8.49)
Net Income	$ 79,330,584.68	$ 62,200,204.72	$ 17,130,379.96	27.54

August 19, 2011

Louisville Gas and Electric 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..	$ 1,058,027,351.36	$ 955,459,809.17	$ 102,567,542.19	10.73
Gas Operating Revenues...	318,430,439.21	283,635,845.48	34,794,593.73	12.27
Total Operating Revenues...	1,376,457,790.57	1,239,095,654.65	137,362,135.92	11.09
Fuel for Electric Generation...	368,280,190.00	335,728,994.22	32,551,195.78	9.70
Power Purchased..	65,527,735.60	55,122,055.29	10,405,680.31	18.88
Gas Supply Expenses..	177,632,731.71	162,153,053.85	15,479,677.86	9.55
Other Operation Expenses..	237,254,832.35	218,447,823.45	18,807,008.90	8.61
Maintenance..	117,036,799.72	64,205,664.10	52,831,135.62	82.28
Depreciation..	137,848,285.06	130,238,348.56	7,609,936.50	5.84
Amortization Expense...	7,767,704.65	8,103,437.20	(335,732.55)	(4.14)
Regulatory Credits..	(6,680,695.16)	(2,179,926.64)	(4,500,768.52)	(206.46)
Taxes				
Federal Income..	21,508,318.42	38,705,374.92	(17,197,056.50)	(44.43)
State Income...	11,733,770.12	3,809,831.74	7,923,938.38	207.99
Deferred Federal Income - Net.................................	41,591,774.72	20,205,709.02	21,386,065.70	105.84
Deferred State Income - Net......................................	(2,274,096.83)	6,597,215.40	(8,871,312.23)	(134.47)
Property and Other..	24,625,051.28	21,885,870.99	2,739,180.29	12.52
Investment Tax Credit...	-	1,824,673.02	(1,824,673.02)	(100.00)
Amortization of Investment Tax Credit.....................	(2,667,976.00)	(2,720,343.56)	52,367.56	1.93
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	3,646,838.10	1,992,053.60	1,654,784.50	83.07
Total Operating Expenses...	1,202,828,685.80	1,064,085,375.02	138,743,310.78	13.04
Net Operating Income..	173,629,104.77	175,010,279.63	(1,381,174.86)	(0.79)
Other Income Less Deductions.................................	16,952,320.66	(4,828,984.79)	21,781,305.45	451.05
Income Before Interest Charges................................	190,581,425.43	170,181,294.84	20,400,130.59	11.99
Interest on Long-Term Debt...	40,539,462.07	43,957,894.11	(3,418,432.04)	(7.78)
Amortization of Debt Expense - Net............................	2,782,368.31	1,412,265.54	1,370,102.77	97.01
Other Interest Expenses..	2,414,829.37	2,731,078.44	(316,249.07)	(11.58)
Total Interest Charges...	45,736,659.75	48,101,238.09	(2,364,578.34)	(4.92)
Net Income..	$ 144,844,765.68	$ 122,080,056.75	$ 22,764,708.93	18.65

August 19, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings
July 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period..	$ 844,832,315.17	$ 771,804,572.18	$ 827,993,251.96	$ 755,278,866.24	$ 787,479,070.96	$ 695,399,014.21
Add:						
Net Income for Period..	20,241,521.47	15,674,498.78	79,330,584.68	62,200,204.72	144,844,765.68	122,080,056.75
Deduct:						
Common Dividends						
Common Stock Without Par Value.....................	-	-	42,250,000.00	30,000,000.00	67,250,000.00	30,000,000.00
Balance at End of Period...	$ 865,073,836.64	$ 787,479,070.96	$ 865,073,836.64	$ 787,479,070.96	$ 865,073,836.64	$ 787,479,070.96

August 19, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of July 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,813,897,037.14	$ 4,596,155,723.91
Less: Reserves for Depreciation and Amortization	2,103,467,014.13	2,020,431,818.86
Total	2,710,430,023.01	2,575,723,905.05
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	22,357,645.64	17,816,924.04
Total	22,963,810.84	18,423,089.24
Current and Accrued Assets		
Cash	38,334,376.50	2,458,207.79
Special Deposits	3,151,789.21	694,039.76
Temporary Cash Investments	18,512,047.18	119.71
Accounts Receivable - Less Reserve	148,476,351.97	152,615,048.85
Accounts Receivable from Associated Companies	11,752,654.76	31,743,790.61
Materials and Supplies - At Average Cost		
Fuel	58,266,316.48	67,057,622.92
Plant Materials and Operating Supplies	30,252,113.88	28,948,754.37
Stores Expense	5,282,243.47	4,880,898.47
Gas Stored Underground	32,199,333.75	34,640,844.19
Emission Allowances	2,114.63	3,467.86
Prepayments	6,527,553.62	6,107,360.76
Miscellaneous Current and Accrued Assets	642,063.90	1,786,668.84
Total	353,398,959.35	330,936,824.13
Deferred Debits and Other		
Unamortized Debt Expense	13,272,796.01	3,745,476.42
Unamortized Loss on Bonds	21,227,628.80	22,439,664.20
Accumulated Deferred Income Taxes	55,536,998.05	51,350,160.00
Deferred Regulatory Assets	359,022,573.48	318,009,867.49
Other Deferred Debits	1,307,123.49	554,607.97
Total	450,367,119.83	396,099,776.08
Total Assets	$ 3,537,159,913.03	$ 3,321,183,594.50

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	(13,202,834.60)
Retained Earnings	865,073,836.64	787,479,070.96
Total Proprietary Capital	1,372,989,871.09	1,282,192,270.81
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds	531,214,934.12	-
LT Notes Payable to Associated Companies	-	485,000,000.00
Total Long-Term Debt	1,105,518,934.12	896,104,000.00
Total Capitalization	2,478,508,805.21	2,178,296,270.81
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	135,048,400.00
Accounts Payable	85,729,649.67	87,363,988.88
Accounts Payable to Associated Companies	12,602,066.24	20,164,038.85
Customer Deposits	22,714,988.20	24,236,689.44
Taxes Accrued	23,590,209.81	18,333,431.49
Interest Accrued	7,939,349.46	3,078,318.40
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	23,212,684.00	20,436,721.44
Total	175,788,947.38	308,661,588.50
Deferred Credits and Other		
Accumulated Deferred Income Taxes	506,075,924.63	442,364,833.95
Investment Tax Credit	43,899,005.13	46,566,981.13
Regulatory Liabilities	60,756,940.33	54,864,073.23
Customer Advances for Construction	8,075,464.10	8,678,961.61
Asset Retirement Obligations	52,226,757.13	34,213,005.28
Other Deferred Credits	23,912,823.90	22,956,121.09
Miscellaneous Long-Term Liabilities	42,351,120.43	47,399,984.45
Accum Provision for Postretirement Benefits	145,564,124.79	177,181,774.45
Total	882,862,160.44	834,225,735.19
Total Liabilities and Stockholders' Equity	$ 3,537,159,913.03	$ 3,321,183,594.50

August 19, 2011

Louisville Gas and Electric 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..	75,000,000	21,294,223	$ 425,170,424.09	
Less: Common Stock Expense..			835,888.64	
Paid-In Capital..			83,581,499.00	
Other Comprehensive Income..			-	
Retained Earnings..			865,073,836.64	
Total Proprietary Capital..			1,372,989,871.09	55.40
Long-Term Debt				
Pollution Control Bonds...				
Jefferson County 2000 Series A due 05/01/27 5.375%................			25,000,000.00	
Trimble County 2000 Series A due 08/01/30 Var%......................			83,335,000.00	
Jefferson County 2001 Series A due 09/01/26 Var%..................			22,500,000.00	
Jefferson County 2001 Series A due 09/01/27 Var%...................			10,104,000.00	
Jefferson County 2001 Series B due 11/01/27 Var%..................			35,000,000.00	
Trimble County 2001 Series A due 09/01/26 Var%......................			27,500,000.00	
Trimble County 2001 Series A due 10/01/32 Var%......................			41,665,000.00	
Trimble County 2001 Series B due 11/01/27 Var%......................			35,000,000.00	
Louisville Metro 2003 Series A due 10/01/33 1.900%.................			128,000,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%.................			40,000,000.00	
Louisville Metro 2007 Series A due 06/01/33 5.625%.................			31,000,000.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%.................			35,200,000.00	
Trimble County 2007 Series A due 06/01/33 4.600%..................			60,000,000.00	
Total Pollution Control Bonds..			574,304,000.00	23.17
First Mortgage Bonds..				
First Mortgage Bond Due 11/15/15 1.625%..................................			250,000,000.00	
First Mortgage Bond Due 11/15/40 5.125%..................................			285,000,000.00	
Total First Mortgage Bonds..			535,000,000.00	21.59
Less: First Mortgage Bonds Debt Discount.....................................				
First Mortgage Bond Due 11/15/15 1.625%..................................			(757,479.19)	
First Mortgage Bond Due 11/15/40 5.125%..................................			(3,027,586.69)	
			(3,785,065.88)	-0.15
Total First Mortgage Bonds - Net of Debt Discount........................			531,214,934.12	21.43
Total Capitalization..			$ 2,478,508,805.21	100.00

August 19, 2011

Louisville Gas and Electric Company
Summary Trial Balance
July 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 4,813,897,037.14	$ 4,813,897,037.14
Reserves for Depreciation and Amortization		(2,103,467,014.13)
Depreciation of Plant		
Electric	(1,764,672,564.83)	
Gas	(235,428,472.71)	
Common	(84,090,054.02)	
Amortization of Plant		
Common	(19,275,022.57)	
Gas	(800.00)	
Electric	(100.00)	
Investments		22,963,810.84
Special Funds	22,357,645.64	
Ohio Valley Electric Corporation	594,286.00	
Nonutility Property	11,879.20	
Cash	38,334,376.50	38,334,376.50
Special Deposits		3,151,789.21
MAN Margin Call	2,455,601.69	
Other Special Deposits	696,187.52	
Temporary Cash Investments	18,512,047.18	18,512,047.18
Accounts Receivable - Less Reserve		148,476,351.97
Customers - Active	72,985,714.63	
Unbilled Revenues	68,727,853.83	
IMPA	2,100,756.45	
IMEA	2,041,846.93	
Bechtel Liquidated Damages	1,480,290.00	
Wholesale Sales	1,178,797.22	
Sundry Accounts Receivable	1,009,928.87	
Transmission Sales	560,409.75	
Damage Claims	323,662.85	
IMEA/IMPA Net Portion of Bechtel Liquidated damages	(370,072.50)	
Other	454,300.37	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	3,716,366.09	
Accrual	(3,014,559.39)	
Reserve	(1,729,197.00)	
Recoveries	(702,982.58)	
A/R Miscellaneous	(286,763.55)	
Accounts Receivable from Associated Companies		11,752,654.76
LG&E - KU Energy Services/Kentucky Utilities	11,752,654.76	
Fuel		58,266,316.48
Coal 1,234,117.26 Tons @ $46.81; MMBtu 28,249,136.28 @ 204.49¢	57,766,414.87	
Fuel Oil 174,564.20 Gallons @ 267.60¢	467,137.51	
Gas Pipeline 5,100 Mcf @ $6.42	32,764.10	
Plant Materials and Operating Supplies		30,252,113.88
Regular Materials and Supplies	29,863,297.30	
Limestone 44,401.44 Tons @ $8.76	388,816.58	
Stores Expense Undistributed	5,282,243.47	5,282,243.47
Gas Stored Underground - Current		32,199,333.75
Gas Stored Underground* 6,366,878 Mcf (14.73 psia) @ $5.06	32,199,333.75	
Emission Allowances	2,114.63	2,114.63

August 19, 2011

Louisville Gas and Electric Company
Summary Trial Balance
July 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Prepayments		$ 6,527,553.62
Insurance	3,614,752.42	
Taxes	1,791,752.66	
Rights of Way	226,666.71	
Franchises	116,678.94	
Risk Management and Workers Compensation	90,000.00	
Other	687,702.89	
Miscellaneous Current Assets		642,063.90
Derivative Asset - Non-Hedging	642,063.90	
Unamortized Debt Expense		13,272,796.01
Trimble County 2000 Series A due 08/01/30 Var%	735,440.09	
Jefferson County 2001 Series A due 09/01/26 Var%	149,683.56	
Jefferson County 2001 Series A due 09/01/27 Var%	327,979.30	
Jefferson County 2001 Series B due 11/01/27 Var%	178,672.81	
Trimble County 2001 Series A due 09/01/26 Var%	162,748.93	
Trimble County 2001 Series B due 11/01/27 Var%	178,702.12	
Trimble County 2002 Series A due 10/01/32 Var%	787,853.23	
Louisville Metro 2003 Series A Due 10/01/33 1.900%	434,679.74	
Louisville Metro 2007 Series B Due 06/01/33 1.900%	163,191.92	
Trimble County 2007 Series A due 06/01/33 4.600%	1,037,834.66	
First Mortgage Bond due 11/15/15 1.625%	2,184,388.64	
First Mortgage Bond due 11/15/40 5.125%	3,440,559.44	
Revolving Credit Agreement	3,491,061.57	
Unamortized Loss on Bonds	21,227,628.80	21,227,628.80
Accumulated Deferred Income Taxes		55,536,998.05
Federal		
Electric	35,552,740.83	
Gas	10,503,489.54	
State		
Electric	7,539,091.61	
Gas	1,941,676.07	
Regulatory Assets		359,022,573.48
Pension and Postretirement Benefits	213,180,670.00	
Interest Rate Swap Ineffectiveness	40,360,122.62	
2009 Winter Storm	39,454,552.05	
2008 Wind Storm	21,186,299.51	
Deferred Taxes - FAS 109		
Federal		
Electric	12,630,478.54	
State		
Electric	2,303,430.74	
Swap Termination	9,044,920.08	
Asset Retirement Obligations		
Electric	8,022,668.58	
Gas	537,315.48	
Common	5,804.93	
Gas Supply Clause/PBR	4,396,510.37	
Fuel Adjustment Clause	4,357,000.00	
Rate Case Expenses	1,072,884.11	
MISO Exit Fee	1,072,063.70	
KCCS Funding	658,530.38	
EKPC FERC Transmission Costs	438,062.00	
CMRG Funding	195,120.00	
General Management Audit	106,140.39	
Other Deferred Debits	1,307,123.49	1,307,123.49
Total Assets	$ 3,537,159,913.03	$ 3,537,159,913.03

* Excludes:

	$	Mcf
Non-recoverable Base Gas	9,648,855.00	7,880,000
Recoverable Base Gas	2,139,990.00	2,930,000
	11,788,845.00	10,810,000

August 19, 2011

Louisville Gas and Electric Company
Summary Trial Balance
July 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 1,372,989,871.09
Common Stock	425,170,424.09	
Less: Common Stock Expense	835,888.64	
Paid-In Capital	83,581,499.00	
Retained Earnings	865,073,836.64	
Pollution Control Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,214,934.12	531,214,934.12
Accounts Payable		85,729,649.67
Regular	84,306,180.96	
Salaries and Wages Accrued	1,429,094.00	
Employee Withholdings Payable	(5,625.29)	
Accounts Payable to Associated Companies		12,602,066.24
LG&E - KU Energy Services/Kentucky Utilities	12,602,066.24	
Customers' Deposits	22,714,988.20	22,714,988.20
Taxes Accrued	23,590,209.81	23,590,209.81
Interest Accrued		7,939,349.46
Jefferson County 2000 Series A due 05/01/27 5.375%	335,937.50	
Trimble County 2000 Series A due 08/01/30 Var%	3,518.59	
Jefferson County 2001 Series A due 09/01/26 Var%	5,609.59	
Jefferson County 2001 Series A due 09/01/27 Var%	134.72	
Jefferson County 2001 Series B due 11/01/27 Var%	4,499.73	
Trimble County 2001 Series A due 09/01/26 Var%	14,706.86	
Trimble County 2001 Series A due 10/01/32 Var%	3,470.18	
Trimble County 2001 Series B due 11/01/27 Var%	4,219.18	
Louisville Metro 2003 Series A due 10/01/33 1.900%	817,422.22	
Louisville Metro 2005 Series A due 02/01/35 5.750%	1,143,611.11	
Louisville Metro 2007 Series A due 06/01/33 5.625%	290,625.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%	113,324.44	
Trimble County 2007 Series A due 06/01/33 4.600%	460,000.00	
Interest Rate Swaps	658,948.20	
First Mortgage Bond due 11/15/15 1.625%	857,638.89	
First Mortgage Bond due 11/15/40 5.125%	3,083,541.67	
Customers' Deposits	131,644.25	
Other	10,497.33	
Miscellaneous Current and Accrued Liabilities		23,212,684.00
Vacation Pay Accrued	6,718,979.89	
Customer Overpayments	4,432,874.91	
No-Notice Gas Payable	3,624,847.68	
SFAS 133 Derivative Liability	3,236,900.16	
Derivative Liabilities - Non-Hedging	1,886,733.59	
Tax Collections Payable	1,294,714.22	
Unearned Revenue	705,804.03	
Postretirement Benefits - Current	624,694.04	
Other	687,135.48	

August 19, 2011

Louisville Gas and Electric Company
Summary Trial Balance
July 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Accumulated Deferred Income Taxes		$ 506,075,924.63
Federal		
Electric	367,237,261.05	
Gas	69,898,654.54	
State		
Electric	58,855,264.31	
Gas	10,084,744.73	
Investment Tax Credit		43,899,005.13
Advanced Coal Credit	23,403,258.00	
Job Development Credit		
Electric	19,883,159.98	
Gas	612,587.15	
Regulatory Liabilities		60,756,940.33
Deferred Taxes		
Federal		
Electric	27,289,225.06	
Gas	1,038,846.36	
State		
Electric	15,697,512.72	
Gas	2,373,942.46	
DSM Cost Recovery	6,925,227.10	
Gas Supply Clause/PBR	3,297,201.39	
Asset Retirement Obligations		
Gas	2,141,450.65	
Electric	262,391.36	
Environmental Cost Recovery	773,608.00	
MISO Schedule 10 Charges	508,859.62	
Purchased Gas Adjustment - Tennessee Gas	448,675.61	
Customers' Advances for Construction		8,075,464.10
Line Extensions		
Gas	6,526,237.39	
Electric	788,492.17	
Customer Advances - Museum Plaza	696,187.52	
Other	64,547.02	
Asset Retirement Obligations		52,226,757.13
Electric	34,836,891.93	
Gas	17,284,215.61	
Common	105,649.59	
Other Deferred Credits	23,912,823.90	23,912,823.90
Miscellaneous Long-Term Liabilities		42,351,120.43
Long-Term Derivative Liabilities - SFAS 133	37,123,222.46	
Workers' Compensation	5,227,897.97	
Accumulated Provision for Benefits		145,564,124.79
Postretirement Benefits - SFAS 106	80,434,583.11	
Pension Payable	61,662,688.50	
Post Employment Benefits Payable	3,698,041.00	
Post Employment Medicare Subsidy	(231,187.82)	
Total Liabilities and Stockholders' Equity	$ 3,537,159,913.03	$ 3,537,159,913.03

August 19, 2011

Louisville Gas and Electric Company
Statement of Cash Flows
July 31, 2011

	Year to Date	
	2011	2010
Cash Flows from Operating Activities		
Net income	$ 79,330,584.68	$ 62,200,204.72
Items not requiring (providing) cash currently:		
Depreciation	82,679,185.68	76,040,903.89
Amortization	4,630,433.55	4,589,717.80
Deferred income taxes - net	30,890,090.70	19,605,513.94
Investment tax credit - net	(1,625,571.00)	(1,459,369.00)
Gain on disposal of assets	(64,610.38)	(33,760.40)
Other	6,806,072.23	24,425,006.17
Change in receivables	25,811,622.87	(36,663,447.65)
Change in inventory	36,519,878.65	14,382,399.85
Change in allowance inventory	614.33	703.14
Change in payables and accrued expenses	6,194,293.57	(30,079,684.34)
Change in regulatory assets	(14,880,069.92)	1,980,227.22
Change in regulatory liabilities	9,330,591.87	(30,043,135.35)
Change in other deferred debits	(17,926,738.41)	56,075.57
Change in other deferred credits	18,312,464.06	14,973,635.41
Pension and postretirement funding	(67,940,500.00)	(24,267,900.00)
Other	1,918,939.42	(2,542,707.41)
Net cash provided (used) by operating activities	199,987,281.90	93,164,383.56
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(77,652,078.92)	(25,310,695.30)
Gross additions to common utility plant - construction expenditures	(3,963,157.57)	(5,485,125.66)
Proceeds received from sales of property	64,610.38	33,760.40
Change in restricted cash	(3,595,499.69)	-
Change in derivatives	-	239,084.83
Reissuance of reacquired bonds as Available for Sale debt securities	163,200,000.00	-
Other	(4,976,208.00)	-
Net cash provided (used) by investing activities	73,077,666.20	(30,522,975.73)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(1,218,536.26)	(26,566.71)
Net change in short-term debt	(174,876,000.00)	(35,352,000.00)
Dividends on common stock	(42,250,000.00)	(30,000,000.00)
Net cash provided (used) by financing activities	(218,344,536.26)	(65,378,566.71)
Net Increase (Decrease) in Cash and Cash Equivalents	54,720,411.84	(2,737,158.88)
Cash and Cash Equivalents at Beginning of Period	2,126,011.84	5,195,486.38
Cash and Cash Equivalents at End of Period	$ 56,846,423.68	$ 2,458,327.50

August 19, 2011

Louisville Gas and Electric 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						
Jefferson County 2000 Series A due 05/01/27 5.375%.......................	$ 111,979.18	$ 111,979.08	$ 783,854.19	$ 783,854.07	$ 1,343,750.04	$ 1,343,749.92
Trimble County 2000 Series A due 08/01/30 Var%............................	7,407.55	35,185.88	126,379.78	237,747.80	279,912.94	343,166.54
Jefferson County 2001 Series A due 09/01/26 Var%..........................	858.84	3,571.48	13,713.24	27,557.26	33,291.11	37,672.66
Jefferson County 2001 Series A due 09/01/27 Var%..........................	6,996.57	17,352.74	135,585.61	89,815.07	234,678.09	171,678.09
Jefferson County 2001 Series B due 11/01/27 Var%..........................	21,426.85	42,220.53	200,403.04	201,887.61	355,020.56	355,935.55
Trimble County 2001 Series A due 09/01/26 Var%............................	7,473.98	15,445.21	62,662.34	101,953.43	125,723.98	205,700.02
Trimble County 2001 Series A due 10/01/32 Var%............................	6,785.11	19,026.63	80,709.07	206,518.37	169,157.59	254,382.91
Trimble County 2001 Series B due 11/01/27 Var%............................	21,479.45	42,431.50	197,773.68	203,047.89	351,275.01	357,095.81
Louisville Metro 2003 Series A due 10/01/33 1.900%.......................	202,666.66	-	1,344,355.44	-	1,344,355.44	37,863.42
Louisville Metro 2005 Series A due 02/01/35 5.750%.......................	191,666.67	191,666.57	1,341,666.65	1,341,666.56	2,300,000.00	2,299,999.91
Louisville Metro 2007 Series A due 06/01/33 5.625%.......................	145,312.49	145,312.46	1,017,187.43	1,017,187.45	1,743,749.93	1,743,749.95
Louisville Metro 2007 Series B due 06/01/33 1.900%........................	55,733.34	-	369,697.80	-	369,697.80	-
Trimble County 2007 Series A due 06/01/33 4.600%.........................	230,000.00	230,000.00	1,610,000.00	1,610,000.00	2,760,000.00	2,760,000.00
Interest Rate Swaps..	658,948.19	724,392.26	4,471,041.80	4,823,438.80	7,345,943.31	7,405,099.28
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/15/15 1.625%..	338,541.66	-	2,369,791.66	-	2,877,604.17	-
First Mortgage Bond due 11/15/40 5.125%..	1,217,187.50	-	8,520,312.50	-	10,346,093.75	-
Fidelia/PPL..	-	2,220,150.01	-	15,541,050.03	7,779,525.00	26,641,800.05
Revolving Credit Agreement...	-	-	185,005.01	-	779,683.35	-
Total...	3,224,464.04	3,798,734.35	22,830,139.24	26,185,724.34	40,539,462.07	43,957,894.11
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense...	178,563.96	15,546.83	1,225,642.97	108,685.36	1,570,332.62	186,275.12
Amortization of Loss on Reacquired Debt..	101,002.97	101,002.98	707,020.79	706,235.83	1,212,035.69	1,225,990.42
Total...	279,566.93	116,549.81	1,932,663.76	814,921.19	2,782,368.31	1,412,265.54
Other Interest Charges						
Customers' Deposits...	116,591.68	109,949.11	814,281.46	817,789.88	1,385,398.04	1,496,916.16
Other Tax Deficiencies..	-	-	-	7,469.00	(24,969.00)	(7,411.00)
Interest on DSM Cost Recovery..	1,623.99	(439.83)	7,819.39	16,420.15	17,814.48	98,551.50
Interest on Debt to Associated Companies..	-	38,613.69	8,862.00	184,927.93	86,355.95	338,565.82
Other Interest Expense...	111,356.29	145,646.67	560,833.41	553,373.68	950,229.90	804,455.96
Total...	229,571.96	293,769.64	1,391,796.26	1,579,980.64	2,414,829.37	2,731,078.44
Total Interest..	$ 3,733,602.93	$ 4,209,053.80	$ 26,154,599.26	$ 28,580,626.17	$ 45,736,659.75	$ 48,101,238.09

August 19, 2011

Louisville Gas and Electric 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	$ 1,450,538.00	$ 1,222,746.10	$ 10,150,774.00	$ 8,557,989.38
Unemployment	$ 3,449.11	$ 3,851.78	$ 114,025.48	$ 125,058.65
FICA	$ 589,889.38	$ 558,988.19	$ 4,628,867.46	$ 4,158,237.54
Public Service Commission Fee	$ 162,886.60	$ 161,096.90	$ 1,129,468.04	$ 1,131,149.44
Federal Income	$ 10,655,071.01	$ 8,612,458.61	$ 11,861,710.75	$ 19,227,999.51
State Income	$ 1,943,174.04	$ 1,570,661.15	$ 7,341,482.30	$ 1,654,879.61
Miscellaneous	$ 3,246.57	$ 7,222.67	$ 30,084.02	$ 27,356.53
Total Charged to Operating Expense	14,808,254.71	12,137,025.40	35,256,412.05	34,882,670.66
Taxes Charged to Other Accounts	(54,688.60)	(12,153,952.53)	1,996,773.35	(2,006,326.36)
Taxes Accrued on Intercompany Accounts	(30,541.59)	(211,579.49)	(1,760,687.75)	(1,700,163.65)
Total Taxes Charged	$ 14,723,024.52	$ (228,506.62)	$ 35,492,497.64	$ 31,176,180.65

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	$ 11,354,131.66	$ 10,247,872.25	$ 11,533,467.12	$ 10,068,536.79
Unemployment	$ 54,386.05	$ 87,909.93	$ 141,918.21	$ 377.77
FICA	$ 590,648.24	$ 3,772,359.37	$ 3,987,529.73	$ 375,477.89
Federal Income	$ (3,741,320.05)	$ 11,643,534.10	$ (2,438,136.00)	$ 10,340,350.05
State Income	$ 229,108.93	$ 7,301,693.26	$ 5,162,379.00	$ 2,368,423.19
Kentucky Sales and Use Tax	$ 1,088,857.95	$ 2,344,153.92	$ 3,009,571.69	$ 423,440.18
Miscellaneous	$ 22,339.97	$ 94,974.81	$ 103,710.84	$ 13,603.94
Totals	$ 9,598,152.75	$ 35,492,497.64	$ 21,500,440.59	$ 23,590,209.81

August 19, 2011

Louisville Gas and Electric Company
Summary of Utility Plant
July 31, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant In Service**						
Common						
Common General Plant..	$ 159,884,459.36	$ 8,162,211.47	$ (663,361.41)	$ -	$ 7,498,850.06	$ 167,383,309.42
Common Intangible Plant......................................	56,455,326.72	7,747,375.80	(1,661,801.58)	-	6,085,574.22	62,540,900.94
	216,339,786.08	15,909,587.27	(2,325,162.99)	-	13,584,424.28	229,924,210.36
Electric						
Electric Distribution...	927,289,038.50	24,654,481.15	(4,862,037.10)	47,153.43	19,839,597.48	947,128,635.98
Electric General Plant..	16,521,615.59	1,289,339.27	(1,934,885.80)	-	(645,546.53)	15,876,069.06
Electric Hydro Production.....................................	41,680,209.14	469,609.90	(55,573.58)	-	414,036.32	42,094,245.46
Electric Intangible Plant...	2,340.29	-	-	-	-	2,340.29
Electric Other Production......................................	229,401,033.01	1,720,153.61	(150,109.82)	38,429.14	1,608,472.93	231,009,505.94
Electric Steam Production......................................	1,930,347,044.43	196,883,429.95	(9,843,160.87)	4,144,130.56	191,184,399.64	2,121,531,444.07
Electric Transmission...	247,742,496.14	4,801,319.84	(951,247.89)	(47,153.43)	3,802,918.52	251,545,414.66
	3,392,983,777.10	229,818,333.72	(17,797,015.06)	4,182,559.70	216,203,878.36	3,609,187,655.46
Gas						
Gas Distribution...	549,799,120.70	33,074,580.91	(547,956.63)	97,729.20	32,624,353.48	582,423,474.18
Gas General Plant..	9,178,093.57	400,882.53	(995,401.23)	(97,729.20)	(692,247.90)	8,485,845.67
Gas Intangible Plant...	1,187.49	-	-	-	-	1,187.49
Gas Storage..	78,415,311.06	2,093,712.47	(1,418,787.23)	-	674,925.24	79,090,236.30
Gas Transmission...	16,661,869.68	320,510.93	(3,581.35)	-	316,929.58	16,978,799.26
	654,055,582.50	35,889,686.84	(2,965,726.44)	-	32,923,960.40	686,979,542.90
Total 101 Accounts..................................	4,263,379,145.68	281,617,607.83	(23,087,904.49)	4,182,559.70	262,712,263.04	4,526,091,408.72
105 **Plant Held For Future Use**						
Electric						
Electric Distribution...	649,014.48	-	-	-	-	649,014.48
Electric Steam Production......................................	4,182,559.70	-	-	(4,182,559.70)	(4,182,559.70)	-
	4,831,574.18	-	-	(4,182,559.70)	(4,182,559.70)	649,014.48
Total 105001..	$ 4,831,574.18	$ -	$ -	$ (4,182,559.70)	$ (4,182,559.70)	$ 649,014.48

August 19, 2011

Louisville Gas and Electric Company
Summary of Utility Plant
July 31, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
106 **Completed Construction Not Classified**						
Common						
Common General Plant...	$ 597,158.63	$ 1,099,979.62	$ -	$ -	$ 1,099,979.62	$ 1,697,138.25
Common Intangible Plant......................................	2,714,931.36	(1,685,522.42)	-	-	(1,685,522.42)	1,029,408.94
	3,312,089.99	(585,542.80)	-	-	(585,542.80)	2,726,547.19
Electric						
Electric Distribution...	11,544,733.90	6,330,238.51	-	-	6,330,238.51	17,874,972.41
Electric General Plant..	50,763.87	(50,763.87)	-	-	(50,763.87)	-
Electric Hydro Production.....................................	16,952.26	427,866.66	-	-	427,866.66	444,818.92
Electric Intangible Plant...	-	-	-	-	-	-
Electric Other Production......................................	1,767,208.21	(139,004.50)	-	-	(139,004.50)	1,628,203.71
Electric Steam Production......................................	15,929,229.77	11,227,629.51	-	-	11,227,629.51	27,156,859.28
Electric Transmission...	35,045,472.82	1,490,405.41	-	-	1,490,405.41	36,535,878.23
	64,354,360.83	19,286,371.72	-	-	19,286,371.72	83,640,732.55
Gas						
Gas Distribution...	24,420,156.16	(8,457,259.81)	-	-	(8,457,259.81)	15,962,896.35
Gas General Plant..	126,992.17	74,776.30	-	-	74,776.30	201,768.47
Gas Intangible Plant...	-	-	-	-	-	-
Gas Storage..	951,426.06	(164,350.06)	-	-	(164,350.06)	787,076.00
Gas Transmission...	-	1,817,919.27	-	-	1,817,919.27	1,817,919.27
	25,498,574.39	(6,728,914.30)	-	-	(6,728,914.30)	18,769,660.09
Total 106 Accounts...................................	93,165,025.21	11,971,914.62	-	-	11,971,914.62	105,136,939.83
117 **Gas Stored Underground-Noncurrent**						
Gas						
Gas Stored Nonrecoverable...................................	2,139,990.00	-	-	-	-	2,139,990.00
	2,139,990.00	-	-	-	-	2,139,990.00
Total 117001...	2,139,990.00	-	-	-	-	2,139,990.00
121 **Nonutility Property**						
Common						
Non Utility Property...	75,239.56	-	-	-	-	75,239.56
	75,239.56	-	-	-	-	75,239.56
Total 121001..	75,239.56	-	-	-	-	75,239.56
107 **Construction Work In Progress**						
Common..	21,243,879.89	(11,360,886.90)	-	-	(11,360,886.90)	9,882,992.99
Electric..	324,323,732.14	(187,757,828.99)	-	-	(187,757,828.99)	136,565,903.15
Gas..	39,756,306.91	(6,325,518.94)	-	-	(6,325,518.94)	33,430,787.97
	385,323,918.94	(205,444,234.83)	-	-	(205,444,234.83)	179,879,684.11
Total Plant (Non-CWIP).......................................	4,363,590,974.63	293,589,522.45	(23,087,904.49)	-	270,501,617.96	4,634,092,592.59
Total Plant + CWIP..	4,748,914,893.57	88,145,287.62	(23,087,904.49)	-	65,057,383.13	4,813,972,276.70
Total Plant + CWIP - Non Utility............................	$ 4,748,839,654.01	$ 88,145,287.62	$ (23,087,904.49)	$ -	$ 65,057,383.13	$ 4,813,897,037.14

August 19, 2011

Louisville Gas and Electric 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										
Common General Plant	$ (77,263,235.10)	$ (7,397,191.78)	$ 663,361.41	$ -	$ -	$ -	$ -	$ -	$ -	$ (83,997,065.47)
Common General Plant - ARO	(343.19)	(1,201.90)	-	-	-	-	-	-	-	(1,545.09)
Electric Distribution	(277,000,365.75)	(10,088,091.65)	4,862,037.10	(382.60)	-	-	-	-	-	(282,226,802.90)
Electric Distribution - ARO	(1,256.54)	(3,519.76)	-	-	-	-	-	-	-	(4,776.30)
Electric General Plant	(12,910,034.19)	(215,945.35)	1,934,885.80	-	-	-	-	-	-	(11,191,093.74)
Electric Hydro Production	(9,718,276.66)	(327,072.89)	55,573.58	-	-	-	-	-	-	(9,989,775.97)
Electric Hydro Production - ARO	(364.10)	(1,019.97)	-	-	-	-	-	-	-	(1,384.07)
Electric Other Production	(60,282,055.17)	(4,771,831.43)	150,109.82	-	-	-	-	-	-	(64,903,776.78)
Electric Other Production - ARO	(192.68)	(627.34)	-	-	-	-	-	-	-	(820.02)
Electric Steam Production	(1,029,518,070.37)	(33,060,257.27)	9,167,484.51	-	-	-	-	-	-	(1,053,410,843.13)
Electric Steam Production - ARO	(204,061.94)	(1,374,543.50)	675,676.36	-	-	-	-	-	-	(902,929.08)
Electric Transmission	(119,192,606.75)	(2,551,518.70)	951,247.89	382.60	-	-	-	-	-	(120,792,494.96)
Electric Transmission - ARO	(41.40)	(115.99)	-	-	-	-	-	-	-	(157.39)
Gas Distribution	(125,049,477.23)	(6,692,183.45)	472,917.36	(13,332.40)	-	-	-	-	-	(131,282,075.72)
Gas Distribution - ARO	(49,734.93)	(247,932.70)	75,039.27	-	-	-	-	-	-	(222,628.36)
Gas General Plant	(6,299,629.20)	(178,300.15)	995,401.23	13,332.40	-	-	-	-	-	(5,469,195.72)
Gas Storage	(31,288,281.49)	(630,112.55)	1,023,381.77	-	-	-	-	-	-	(30,895,012.27)
Gas Storage - ARO	(39,466.10)	(521,748.34)	395,405.46	-	-	-	-	-	-	(165,808.98)
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(9,448,605.32)	(32,866.72)	3,581.35	-	-	-	-	-	-	(9,477,890.69)
Non Utility Property	(63,360.36)	-	-	-	-	-	-	-	-	(63,360.36)
	(1,758,329,458.47)	(68,096,081.44)	21,426,102.91	-	-	-	-	-	-	(1,804,999,437.00)
Cost Of Removal										
Common General Plant	(688,372.47)	(162,647.28)	-	-	-	-	332,962.76	-	-	(518,056.99)
Electric Distribution	(146,715,298.78)	(3,995,338.57)	-	(55.48)	-	-	2,687,396.25	-	-	(148,023,296.58)
Electric General Plant	3,866.64	-	-	-	-	-	-	-	-	3,866.64
Electric Hydro Production	736,907.70	(24,836.95)	-	-	-	-	34,591.42	-	-	746,662.17
Electric Other Production	(2,505,175.99)	(204,924.54)	-	-	-	-	104,342.09	-	-	(2,605,758.44)
Electric Steam Production	(94,783,295.15)	(9,876,028.42)	-	-	-	-	2,411,346.44	-	-	(102,247,977.13)
Electric Transmission	(24,538,454.78)	(821,312.98)	-	55.48	-	-	86,594.48	-	-	(25,273,117.80)
Gas Distribution	(60,212,131.14)	(1,888,432.44)	-	-	-	-	1,477,138.22	-	-	(60,623,425.36)
Gas General Plant	(0.02)	-	-	-	-	-	-	-	-	(0.02)
Gas Storage	(170,437.90)	(81,641.20)	-	-	-	-	565,052.30	-	-	312,973.20
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(3,016,813.95)	(8,129.80)	-	-	-	-	42,869.45	-	-	(2,982,074.30)
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	$ (331,889,205.84)	$ (17,063,292.18)	$ -	$ -	$ -	$ -	$ 7,742,293.41	$ -	$ -	$ (341,210,204.61)

August 19, 2011

Louisville Gas and Electric 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
Salvage										
Common General Plant..	$ 278,074.55	$ 223.58	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 278,298.13
Electric Distribution...	17,535,024.98	809,252.13	-	-	-	-	-	(182,166.06)	-	18,162,111.05
Electric General Plant..	138,281.25	1,347.85	-	-	-	-	-	-	-	139,629.10
Electric Hydro Production..	376,638.17	-	-	-	-	-	-	-	-	376,638.17
Electric Other Production...	(18,998.67)	-	-	-	-	-	-	-	-	(18,998.67)
Electric Steam Production..	22,028,570.14	1,175,998.44	-	-	-	-	-	(26,976.51)	-	23,177,592.07
Electric Transmission...	6,247,368.67	152,204.77	-	-	-	-	-	-	-	6,399,573.44
Gas Distribution..	3,594,440.75	115,423.37	-	-	-	-	-	-	-	3,709,864.12
Gas General Plant...	225,788.37	1,283.77	-	-	-	-	-	-	-	227,072.14
Gas Storage..	269,933.04	9,993.36	-	-	-	-	-	-	-	279,926.40
Gas Stored Nonrecoverable..	-	-	-	-	-	-	-	-	-	-
Gas Transmission...	217,923.11	3,048.67	-	-	-	-	-	-	-	220,971.78
Non Utility Property..	-	-	-	-	-	-	-	-	-	-
	50,893,044.36	2,268,775.94	-	-	-	-	-	(209,142.57)	-	52,952,677.73
Total Reserves										
Common..	(77,737,236.57)	(7,560,817.38)	663,361.41	-	-	-	332,962.76	-	-	(84,301,729.78)
Electric..	(1,730,321,891.37)	(65,178,182.12)	17,797,015.06	-	-	-	5,324,270.68	(209,142.57)	-	(1,772,587,930.32)
Gas..	(231,266,492.01)	(10,151,598.18)	2,965,726.44	-	-	-	2,085,059.97	-	-	(236,367,303.78)
	(2,039,325,619.95)	(82,890,597.68)	21,426,102.91	-	-	-	7,742,293.41	(209,142.57)	-	(2,093,256,963.88)
Retirement Work In Progress										
Common..	342,947.00	-	-	162,020.85	-	(332,962.76)	(5,795.69)	(17,894.00)	-	148,315.40
Electric..	9,603,653.21	-	-	(35,892.93)	(909,868.03)	(4,773,505.32)	4,364,519.26	(246,610.78)	(86,929.92)	7,915,365.49
Gas..	2,523,160.64	-	-	(66,835.06)	(1,053,809.06)	(1,289,256.25)	832,807.42	(4,846.40)	(2,390.22)	938,831.07
	12,469,760.85	-	-	59,292.86	(1,963,677.09)	(6,395,724.33)	5,191,530.99	(269,351.18)	(89,320.14)	9,002,511.96
YTD ACTIVITY	(2,026,855,859.10)	(82,890,597.68)	21,426,102.91	59,292.86	(1,963,677.09)	(6,395,724.33)	12,933,824.40	(478,493.75)	(89,320.14)	(2,084,254,451.92)
Amortization										
Common..	(16,306,390.60)	(4,630,433.55)	1,661,801.58	-	-	-	-	-	-	(19,275,022.57)
Electric..	(100.00)	-	-	-	-	-	-	-	-	(100.00)
Gas..	(800.00)	-	-	-	-	-	-	-	-	(800.00)
AMORTIZATION TOTAL	(16,307,290.60)	(4,630,433.55)	1,661,801.58	-	-	-	-	-	-	(19,275,922.57)
Depreciation & Amortization Total	$ (2,043,163,149.70)	$ (87,521,031.23)	$ 23,087,904.49	$ 59,292.86	$ (1,963,677.09)	$ (6,395,724.33)	$ 12,933,824.40	$ (478,493.75)	$ (89,320.14)	$ (2,103,530,374.49)
Depr & Amort - Nonutility for Balance Sheet										(2,103,467,014.13)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)....................................	$ 2,705,739,864.67									$ 2,710,430,023.01

August 19, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
July 31, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues...	$ 115,642,800.22	$ -	$ 115,642,800.22
Gas Operating Revenues...	11,094,275.90	-	11,094,275.90
Total Operating Revenues..	126,737,076.12	-	126,737,076.12
Fuel for Electric Generation..	36,648,656.50	-	36,648,656.50
Power Purchased..	6,917,723.12	-	6,917,723.12
Gas Supply Expenses...	4,139,144.22	-	4,139,144.22
Other Operation Expenses...	20,283,093.61	-	20,283,093.61
Maintenance..	8,077,456.56	-	8,077,456.56
Depreciation..	11,822,081.46	-	11,822,081.46
Amortization Expense...	689,686.28	-	689,686.28
Regulatory Credits...	(386,874.71)	-	(386,874.71)
Taxes			
Federal Income..	10,655,071.01	-	10,655,071.01
State Income..	1,943,174.04	-	1,943,174.04
Deferred Federal Income - Net...................................	-	8,230.80	8,230.80
Deferred State Income - Net.......................................	-	1,501.06	1,501.06
Property and Other..	2,210,009.66	-	2,210,009.66
Investment Tax Credit..	-	-	-
Amortization of Investment Tax Credit......................	(236,034.00)	-	(236,034.00)
Loss (Gain) from Disposition of Allowances................	-	-	-
Accretion Expense...	215,963.40	-	215,963.40
Total Operating Expenses...	102,979,151.15	9,731.86	102,988,883.01
Net Operating Income..	23,757,924.97	(9,731.86)	23,748,193.11
Other Income Less Deductions...................................	217,199.43	-	217,199.43
Income Before Interest Charges.................................	23,975,124.40	(9,731.86)	23,965,392.54
Interest on Long-Term Debt..	3,224,464.04	(25,017.63)	3,199,446.41
Amortization of Debt Expense - Net.............................	279,566.93	-	279,566.93
Other Interest Expenses..	229,571.96	-	229,571.96
Total Interest Charges...	3,733,602.93	(25,017.63)	3,708,585.30
Net Income...	$ 20,241,521.47	$ 15,285.77	$ 20,256,807.24

Note: Purchase accounting is subject to change through October 31, 2011

August 19, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
July 31, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues.......................................	$ 624,086,509.87	$ -	$ 624,086,509.87
Gas Operating Revenues...	194,396,784.05	-	194,396,784.05
Total Operating Revenues..	818,483,293.92	-	818,483,293.92
Fuel for Electric Generation..	209,021,593.25	-	209,021,593.25
Power Purchased...	44,349,720.70	-	44,349,720.70
Gas Supply Expenses..	108,254,395.80	-	108,254,395.80
Other Operation Expenses...	137,049,951.30	27,884.66	137,077,835.96
Maintenance..	66,800,103.67	-	66,800,103.67
Depreciation..	82,679,185.68	-	82,679,185.68
Amortization Expense...	4,630,433.55	-	4,630,433.55
Regulatory Credits...	(3,682,818.11)	-	(3,682,818.11)
Taxes			
Federal Income...	11,861,710.75	-	11,861,710.75
State Income..	7,341,482.30	-	7,341,482.30
Deferred Federal Income - Net.................................	29,108,145.53	48,441.57	29,156,587.10
Deferred State Income - Net.....................................	(221,983.14)	8,834.35	(213,148.79)
Property and Other...	16,053,219.00	-	16,053,219.00
Investment Tax Credit..	-	-	-
Amortization of Investment Tax Credit....................	(1,625,571.00)	-	(1,625,571.00)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	-	(2,577.94)
Accretion Expense..	1,532,108.61	-	1,532,108.61
Total Operating Expenses..	713,149,099.95	85,160.58	713,234,260.53
Net Operating Income...	105,334,193.97	(85,160.58)	105,249,033.39
Other Income Less Deductions.................................	150,989.97	-	150,989.97
Income Before Interest Charges................................	105,485,183.94	(85,160.58)	105,400,023.36
Interest on Long-Term Debt..	22,830,139.24	(175,123.41)	22,655,015.83
Amortization of Debt Expense - Net...........................	1,932,663.76	-	1,932,663.76
Other Interest Expenses...	1,391,796.26	-	1,391,796.26
Total Interest Charges..	26,154,599.26	(175,123.41)	25,979,475.85
Net Income..	$ 79,330,584.68	$ 89,962.83	$ 79,420,547.51

Note: Purchase accounting is subject to change through October 31, 2011

August 19, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
July 31, 2011

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period………………………………	$ 844,832,315.17	$ 771,804,572.18	$ (808,824,605.38)	$ -	$ 36,007,709.79	$ 771,804,572.18
Add:						
Net Income (Loss) for Period…………………………	20,241,521.47	15,674,498.78	15,285.77	-	20,256,807.24	15,674,498.78
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	-	-	-	-	-	-
Balance at End of Period…………………………………	$ 865,073,836.64	$ 787,479,070.96	$ (808,809,319.61)	$ -	$ 56,264,517.03	$ 787,479,070.96

Note: Purchase accounting is subject to change through October 31, 2011

August 19, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
July 31, 2011

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……………………………	$ 827,993,251.96	$ 755,278,866.24	$ (808,899,282.44)	$ -	$ 19,093,969.52	$ 755,278,866.24
Add:						
Net Income (Loss) for Period…………………………	79,330,584.68	62,200,204.72	89,962.83	-	79,420,547.51	62,200,204.72
Deduct:						
Adjustment to Retained Earnings……………………	-	-		-	-	-
Common Dividends						
Common Stock Without Par Value………………	42,250,000.00	30,000,000.00	-	-	42,250,000.00	30,000,000.00
Balance at End of Period…………………………………	$ 865,073,836.64	$ 787,479,070.96	$ (808,809,319.61)	$ -	$ 56,264,517.03	$ 787,479,070.96

Note: Purchase accounting is subject to change through October 31, 2011

August 19, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
July 31, 2011

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……	$ 787,479,070.96	$ 695,399,014.21	$ -	$ -	$ 787,479,070.96	$ 695,399,014.21
Add:						
Net Income (Loss) for Period……	144,844,765.68	122,080,056.75	137,571.91	-	144,982,337.59	122,080,056.75
Deduct:						
Adjustment to Retained Earnings……	-	-	808,946,891.52	-	808,946,891.52	-
Common Dividends						
Common Stock Without Par Value……	67,250,000.00	30,000,000.00	-	-	67,250,000.00	30,000,000.00
Balance at End of Period……	$ 865,073,836.64	$ 787,479,070.96	$ (808,809,319.61)	$ -	$ 56,264,517.03	$ 787,479,070.96

Note: Purchase accounting is subject to change through October 31, 2011

August 19, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of July 31, 2011

Assets	Without Purchase Accounting	Purchase Accounting	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 4,813,897,037.14	$ -	$ 4,813,897,037.14
Less: Reserves for Depreciation and Amortization....	2,103,467,014.13	-	2,103,467,014.13
Total..	2,710,430,023.01	-	2,710,430,023.01
Investments			
Ohio Valley Electric Corporation.............................	594,286.00	-	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	-	11,879.20
Special Funds...	22,357,645.64	-	22,357,645.64
Total..	22,963,810.84	-	22,963,810.84
Current and Accrued Assets			
Cash..	38,334,376.50	-	38,334,376.50
Special Deposits..	3,151,789.21	-	3,151,789.21
Temporary Cash Investments..................................	18,512,047.18	-	18,512,047.18
Accounts Receivable - Less Reserve........................	148,476,351.97	-	148,476,351.97
Accounts Receivable from Associated Companies....	11,752,654.76	-	11,752,654.76
Materials and Supplies - At Average Cost			
Fuel..	58,266,316.48	-	58,266,316.48
Plant Materials and Operating Supplies.................	30,252,113.88	-	30,252,113.88
Stores Expense...	5,282,243.47	-	5,282,243.47
Gas Stored Underground.......................................	32,199,333.75	-	32,199,333.75
Emission Allowances...	2,114.63	-	2,114.63
Prepayments...	6,527,553.62	-	6,527,553.62
Miscellaneous Current and Accrued Assets..............	642,063.90	-	642,063.90
Total..	353,398,959.35	-	353,398,959.35
Deferred Debits and Other			
Unamortized Debt Expense......................................	13,272,796.01	(3,558,914.70)	9,713,881.31
Unamortized Loss on Bonds....................................	21,227,628.80	-	21,227,628.80
Accumulated Deferred Income Taxes.......................	55,536,998.05	77,778,242.30	133,315,240.35
Deferred Regulatory Assets.....................................	359,022,573.48	10,944,924.82	369,967,498.30
Other Deferred Debits...	1,307,123.49	181,592,294.43	182,899,417.92
Goodwill...	-	389,157,351.59	389,157,351.59
Total..	450,367,119.83	655,913,898.44	1,106,281,018.27
Total Assets..	$ 3,537,159,913.03	$ 655,913,898.44	$ 4,193,073,811.47

Note: Purchase accounting is subject to change through October 31, 2011

August 19, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of July 31, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting	Total
Proprietary Capital			
Common Stock	$ 425,170,424.09	$ -	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	-	835,888.64
Paid-In Capital	83,581,499.00	1,194,085,869.02	1,277,667,368.02
Other Comprehensive Income	-	-	-
Retained Earnings	865,073,836.64	(808,809,319.61)	56,264,517.03
Total Proprietary Capital	1,372,989,871.09	385,276,549.41	1,758,266,420.50
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	6,351,558.33	580,655,558.33
First Mortgage Bonds	531,214,934.12	-	531,214,934.12
LT Notes Payable to Associated Companies	-	-	-
Total Long-Term Debt	1,105,518,934.12	6,351,558.33	1,111,870,492.45
Total Capitalization	2,478,508,805.21	391,628,107.74	2,870,136,912.95
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies	-	-	-
Accounts Payable	85,729,649.67	-	85,729,649.67
Accounts Payable to Associated Companies	12,602,066.24	-	12,602,066.24
Customer Deposits	22,714,988.20	-	22,714,988.20
Taxes Accrued	23,590,209.81	-	23,590,209.81
Dividends Declared	-	-	-
Interest Accrued	7,939,349.46	-	7,939,349.46
Miscellaneous Current and Accrued Liabilities	23,212,684.00	-	23,212,684.00
Total	175,788,947.38	-	175,788,947.38
Deferred Credits and Other			
Accumulated Deferred Income Taxes	506,075,924.63	75,307,486.15	581,383,410.78
Investment Tax Credit	43,899,005.13	-	43,899,005.13
Regulatory Liabilities	60,756,940.33	181,592,294.43	242,349,234.76
Customer Advances for Construction	8,075,464.10	-	8,075,464.10
Asset Retirement Obligations	52,226,757.13	-	52,226,757.13
Other Deferred Credits	23,912,823.90	7,386,010.12	31,298,834.02
Miscellaneous Long-Term Liabilities	42,351,120.43	-	42,351,120.43
Misc Long-Term Liab Due to Assoc Cos	-	-	-
Accum Provision for Postretirement Benefits	145,564,124.79	-	145,564,124.79
Total	882,862,160.44	264,285,790.70	1,147,147,951.14
Total Liabilities and Stockholders' Equity	$ 3,537,159,913.03	$ 655,913,898.44	$ 4,193,073,811.47

Note: Purchase accounting is subject to change through October 31, 2011

August 19, 2011

LOUISVILLE GAS AND ELECTRIC COMPANY

Financial Reports

June 30, 2011

Index
Financial and Operating Reports

Louisville Gas and Electric 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.

Louisville Gas and Electric Company
Comparative Statement of Income
June 30, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 95,926,278.08	$ 97,419,852.20	$ (1,493,574.12)	(1.53)
Gas Operating Revenues	11,394,622.50	8,895,903.28	2,498,719.22	28.09
Total Operating Revenues	107,320,900.58	106,315,755.48	1,005,145.10	0.95
Fuel for Electric Generation	29,573,632.96	32,900,469.91	(3,326,836.95)	(10.11)
Power Purchased	6,493,106.90	4,617,350.32	1,875,756.58	40.62
Gas Supply Expenses	4,073,116.36	3,284,952.32	788,164.04	23.99
Other Operation Expenses	20,233,157.90	16,447,189.56	3,785,968.34	23.02
Maintenance	10,121,123.40	8,598,520.45	1,522,602.95	17.71
Depreciation	11,775,559.24	10,931,590.70	843,968.54	7.72
Amortization Expense	684,362.07	616,107.73	68,254.34	11.08
Regulatory Credits	(359,386.42)	(183,360.62)	(176,025.80)	(96.00)
Taxes				
Federal Income	(6,622,269.54)	(6,229,769.94)	(392,499.60)	(6.30)
State Income	840,976.77	(2,847,086.07)	3,688,062.84	129.54
Deferred Federal Income - Net	12,018,131.58	13,262,499.57	(1,244,367.99)	(9.38)
Deferred State Income - Net	44,957.43	4,021,225.36	(3,976,267.93)	(98.88)
Property and Other	2,316,570.56	1,960,428.66	356,141.90	18.17
Investment Tax Credit	-	-	-	-
Amortization of Investment Tax Credit	(236,034.00)	(208,481.00)	(27,553.00)	(13.22)
Loss (Gain) from Disposition of Allowances	-	-	-	-
Accretion Expense	215,040.82	168,720.88	46,319.94	27.45
Total Operating Expenses	91,172,046.03	87,340,357.83	3,831,688.20	4.39
Net Operating Income	16,148,854.55	18,975,397.65	(2,826,543.10)	(14.90)
Other Income Less Deductions	829,607.98	(2,409,600.40)	3,239,208.38	134.43
Income Before Interest Charges	16,978,462.53	16,565,797.25	412,665.28	2.49
Interest on Long-Term Debt	3,246,104.49	3,853,724.62	(607,620.13)	(15.77)
Amortization of Debt Expense - Net	277,604.34	116,549.81	161,054.53	138.19
Other Interest Expenses	426,202.12	366,326.42	59,875.70	16.34
Total Interest Charges	3,949,910.95	4,336,600.85	(386,689.90)	(8.92)
Net Income	$ 13,028,551.58	$ 12,229,196.40	$ 799,355.18	6.54

July 27, 2011

Louisville Gas and Electric Company
Comparative Statement of Income
June 30, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 508,443,709.65	$ 477,506,497.63	$ 30,937,212.02	6.48
Gas Operating Revenues	183,302,508.15	169,407,175.22	13,895,332.93	8.20
Total Operating Revenues	691,746,217.80	646,913,672.85	44,832,544.95	6.93
Fuel for Electric Generation	172,372,936.75	173,255,707.38	(882,770.63)	(0.51)
Power Purchased	37,431,997.58	29,324,114.25	8,107,883.33	27.65
Gas Supply Expenses	104,115,251.58	95,922,113.42	8,193,138.16	8.54
Other Operation Expenses	116,766,857.69	108,155,892.84	8,610,964.85	7.96
Maintenance	58,722,647.11	53,799,164.95	4,923,482.16	9.15
Depreciation	70,857,104.22	65,058,284.25	5,798,819.97	8.91
Amortization Expense	3,940,747.27	3,968,065.72	(27,318.45)	(0.69)
Regulatory Credits	(3,295,943.40)	(1,087,649.67)	(2,208,293.73)	(203.03)
Taxes				
Federal Income	1,206,639.74	10,615,540.90	(9,408,901.16)	(88.63)
State Income	5,398,308.26	84,218.46	5,314,089.80	6,309.89
Deferred Federal Income - Net	29,108,145.53	15,183,379.56	13,924,765.97	91.71
Deferred State Income - Net	(221,983.14)	4,422,138.13	(4,644,121.27)	(105.02)
Property and Other	13,843,209.34	12,045,885.90	1,797,323.44	14.92
Investment Tax Credit	-	-	-	-
Amortization of Investment Tax Credit	(1,389,537.00)	(1,250,888.00)	(138,649.00)	(11.08)
Loss (Gain) from Disposition of Allowances	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense	1,316,145.21	999,811.17	316,334.04	31.64
Total Operating Expenses	610,169,948.80	570,461,319.12	39,708,629.68	6.96
Net Operating Income	81,576,269.00	76,452,353.73	5,123,915.27	6.70
Other Income Less Deductions	(66,209.46)	(5,555,075.42)	5,488,865.96	98.81
Income Before Interest Charges	81,510,059.54	70,897,278.31	10,612,781.23	14.97
Interest on Long-Term Debt	19,605,675.20	22,386,989.99	(2,781,314.79)	(12.42)
Amortization of Debt Expense - Net	1,653,096.83	698,371.38	954,725.45	136.71
Other Interest Expenses	1,162,224.30	1,286,211.00	(123,986.70)	(9.64)
Total Interest Charges	22,420,996.33	24,371,572.37	(1,950,576.04)	(8.00)
Net Income	$ 59,089,063.21	$ 46,525,705.94	$ 12,563,357.27	27.00

July 27, 2011

Louisville Gas and Electric 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..	$ 1,046,548,778.99	$ 935,076,467.37	$ 111,472,311.62	11.92
Gas Operating Revenues...	316,842,688.81	284,538,289.02	32,304,399.79	11.35
Total Operating Revenues...	1,363,391,467.80	1,219,614,756.39	143,776,711.41	11.79
Fuel for Electric Generation...	367,673,555.71	328,141,927.37	39,531,628.34	12.05
Power Purchased..	62,487,602.02	54,655,291.75	7,832,310.27	14.33
Gas Supply Expenses...	177,196,746.21	162,799,512.15	14,397,234.06	8.84
Other Operation Expenses..	235,423,969.42	218,845,930.78	16,578,038.64	7.58
Maintenance..	116,624,587.24	63,595,949.51	53,028,637.73	83.38
Depreciation..	137,008,823.24	130,048,175.79	6,960,647.45	5.35
Amortization Expense...	7,699,670.45	8,234,080.67	(534,410.22)	(6.49)
Regulatory Credits..	(6,478,025.18)	(2,175,140.87)	(4,302,884.31)	(197.82)
Taxes				
Federal Income..	19,465,706.02	34,726,063.50	(15,260,357.48)	(43.95)
State Income...	11,361,257.23	3,084,121.45	8,277,135.78	268.38
Deferred Federal Income - Net.................................	41,591,770.97	20,205,712.77	21,386,058.20	105.84
Deferred State Income - Net......................................	(2,274,096.83)	6,597,215.40	(8,871,312.23)	(134.47)
Property and Other..	24,368,947.26	22,171,603.10	2,197,344.16	9.91
Investment Tax Credit...	-	1,824,673.02	(1,824,673.02)	(100.00)
Amortization of Investment Tax Credit.....................	(2,640,423.00)	(2,766,595.56)	126,172.56	4.56
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	3,600,439.67	1,987,227.75	1,613,211.92	81.18
Total Operating Expenses...	1,193,107,952.49	1,051,941,288.44	141,166,664.05	13.42
Net Operating Income..	170,283,515.31	167,673,467.95	2,610,047.36	1.56
Other Income Less Deductions.................................	16,206,338.30	(3,922,646.89)	20,128,985.19	513.15
Income Before Interest Charges................................	186,489,853.61	163,750,821.06	22,739,032.55	13.89
Interest on Long-Term Debt...	41,113,732.38	43,880,897.82	(2,767,165.44)	(6.31)
Amortization of Debt Expense - Net............................	2,619,351.19	1,419,948.42	1,199,402.77	84.47
Other Interest Expenses..	2,479,027.05	2,807,513.67	(328,486.62)	(11.70)
Total Interest Charges...	46,212,110.62	48,108,359.91	(1,896,249.29)	(3.94)
Net Income..	$ 140,277,742.99	$ 115,642,461.15	$ 24,635,281.84	21.30

July 27, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings
June 30, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period..	$ 831,803,763.59	$ 759,575,375.78	$ 827,993,251.96	$ 755,278,866.24	$ 771,804,572.18	$ 686,162,111.03
Add:						
Net Income for Period..	13,028,551.58	12,229,196.40	59,089,063.21	46,525,705.94	140,277,742.99	115,642,461.15
Deduct:						
Common Dividends						
Common Stock Without Par Value.....................	-	-	42,250,000.00	30,000,000.00	67,250,000.00	30,000,000.00
Balance at End of Period...	$ 844,832,315.17	$ 771,804,572.18	$ 844,832,315.17	$ 771,804,572.18	$ 844,832,315.17	$ 771,804,572.18

July 27, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of June 30, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost.....................................	$ 4,802,348,313.16	$ 4,586,733,561.50
Less: Reserves for Depreciation and Amortization....	2,092,493,560.06	2,011,388,361.15
Total...	2,709,854,753.10	2,575,345,200.35
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve............................	11,879.20	11,879.20
Special Funds...	22,505,965.16	17,054,543.60
Total...	23,112,130.36	17,660,708.80
Current and Accrued Assets		
Cash..	41,156,614.54	5,546,990.55
Special Deposits..	4,626,601.12	693,958.65
Temporary Cash Investments....................................	10,763.48	119.71
Accounts Receivable - Less Reserve.........................	126,976,576.30	154,587,253.55
Accounts Receivable from Associated Companies....	12,749,748.11	17,787,025.30
Materials and Supplies - At Average Cost................		
Fuel..	67,711,396.61	69,073,218.18
Plant Materials and Operating Supplies.................	29,950,707.42	29,037,290.76
Stores Expense...	5,157,847.02	4,733,941.15
Gas Stored Underground..	19,007,070.36	19,129,762.47
Emission Allowances..	2,233.53	3,713.56
Prepayments..	7,798,435.51	4,924,681.40
Miscellaneous Current and Accrued Assets..............	605,541.52	1,882,811.38
Total...	315,753,535.52	307,400,766.66
Deferred Debits and Other		
Unamortized Debt Expense.......................................	13,247,160.62	3,761,023.23
Unamortized Loss on Bonds......................................	21,328,631.75	22,540,667.15
Accumulated Deferred Income Taxes.......................	55,536,998.05	50,944,309.61
Deferred Regulatory Assets.......................................	355,709,240.35	319,055,168.65
Other Deferred Debits...	1,478,646.74	1,202,822.23
Total...	447,300,677.51	397,503,990.87
Total Assets..	$ 3,496,021,096.49	$ 3,297,910,666.68

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense..................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income..................................	-	(12,554,675.38)
Retained Earnings...	844,832,315.17	771,804,572.18
Total Proprietary Capital..	1,352,748,349.62	1,267,165,931.25
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds..	531,191,612.46	-
LT Notes Payable to Associated Companies............	-	485,000,000.00
Total Long-Term Debt..	1,105,495,612.46	896,104,000.00
Total Capitalization..	2,458,243,962.08	2,163,269,931.25
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies............	-	137,358,400.00
Accounts Payable..	85,621,470.31	79,568,208.23
Accounts Payable to Associated Companies............	13,004,765.06	27,944,985.02
Customer Deposits..	22,604,581.72	24,032,890.71
Taxes Accrued..	10,103,469.64	8,213,597.22
Interest Accrued..	5,332,202.80	2,307,571.20
Dividends Declared...	-	-
Miscellaneous Current and Accrued Liabilities........	25,114,319.95	22,705,173.97
Total..	161,780,809.48	302,130,826.35
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	506,075,924.63	442,371,641.52
Investment Tax Credit...	44,135,039.13	46,775,462.13
Regulatory Liabilities..	59,639,476.44	54,630,645.87
Customer Advances for Construction.......................	8,117,149.39	8,624,175.20
Asset Retirement Obligations...................................	52,117,276.38	34,043,440.31
Other Deferred Credits..	21,631,372.89	21,536,826.65
Miscellaneous Long-Term Liabilities.......................	37,441,515.45	45,873,512.45
Accum Provision for Postretirement Benefits...........	146,838,570.62	178,654,204.95
Total..	875,996,324.93	832,509,909.08
Total Liabilities and Stockholders' Equity.....................	$ 3,496,021,096.49	$ 3,297,910,666.68

July 27, 2011

Louisville Gas and Electric 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..	75,000,000	21,294,223	$ 425,170,424.09	
Less: Common Stock Expense..			835,888.64	
Paid-In Capital..			83,581,499.00	
Other Comprehensive Income..			-	
Retained Earnings..			844,832,315.17	
Total Proprietary Capital..			1,352,748,349.62	55.03
Long-Term Debt				
Pollution Control Bonds...				
Jefferson County 2000 Series A due 05/01/27 5.375%.................			25,000,000.00	
Trimble County 2000 Series A due 08/01/30 Var%......................			83,335,000.00	
Jefferson County 2001 Series A due 09/01/26 Var%...................			22,500,000.00	
Jefferson County 2001 Series A due 09/01/27 Var%....................			10,104,000.00	
Jefferson County 2001 Series B due 11/01/27 Var%...................			35,000,000.00	
Trimble County 2001 Series A due 09/01/26 Var%......................			27,500,000.00	
Trimble County 2001 Series A due 10/01/32 Var%......................			41,665,000.00	
Trimble County 2001 Series B due 11/01/27 Var%......................			35,000,000.00	
Louisville Metro 2003 Series A due 10/01/33 1.900%..................			128,000,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%..................			40,000,000.00	
Louisville Metro 2007 Series A due 06/01/33 5.625%..................			31,000,000.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%..................			35,200,000.00	
Trimble County 2007 Series A due 06/01/33 4.600%...................			60,000,000.00	
Total Pollution Control Bonds...			574,304,000.00	23.36
First Mortgage Bonds...				
First Mortgage Bond Due 11/15/15 1.625%..................................			250,000,000.00	
First Mortgage Bond Due 11/15/40 5.125%..................................			285,000,000.00	
Total First Mortgage Bonds...			535,000,000.00	21.76
Less: First Mortgage Bonds Debt Discount.....................................				
First Mortgage Bond Due 11/15/15 1.625%..................................			(772,187.52)	
First Mortgage Bond Due 11/15/40 5.125%..................................			(3,036,200.02)	
			(3,808,387.54)	-0.15
Total First Mortgage Bonds - Net of Debt Discount........................			531,191,612.46	21.61
Total Capitalization...			$ 2,458,243,962.08	100.00

July 27, 2011

Louisville Gas and Electric Company
Summary Trial Balance
June 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 4,802,348,313.16	$ 4,802,348,313.16
Reserves for Depreciation and Amortization		(2,092,493,560.06)
Depreciation of Plant		
Electric	(1,756,378,028.20)	
Gas	(234,224,361.39)	
Common	(83,304,934.18)	
Amortization of Plant		
Common	(18,585,336.29)	
Gas	(800.00)	
Electric	(100.00)	
Investments		23,112,130.36
Special Funds	22,505,965.16	
Ohio Valley Electric Corporation	594,286.00	
Nonutility Property	11,879.20	
Cash	41,156,614.54	41,156,614.54
Special Deposits		4,626,601.12
MAN Margin Call	3,930,413.60	
Other Special Deposits	696,187.52	
Temporary Cash Investments	10,763.48	10,763.48
Accounts Receivable - Less Reserve		126,976,576.30
Customers - Active	65,354,242.99	
Unbilled Revenues	52,952,779.02	
Wholesale Sales	2,314,797.00	
IMPA	2,019,304.96	
IMEA	1,992,992.36	
Sundry Accounts Receivable	1,592,770.46	
Bechtel Liquidated Damages	1,485,990.00	
Rents Receivable	528,837.70	
Transmission Sales	474,349.34	
Damage Claims	322,483.08	
IMEA/IMPA Net Portion of Bechtel Liquidated damages	(371,497.50)	
Other	333,593.44	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	2,847,006.74	
Accrual	(2,228,735.49)	
Reserve	(1,737,303.00)	
Recoveries	(618,271.25)	
A/R Miscellaneous	(286,763.55)	
Accounts Receivable from Associated Companies		12,749,748.11
LG&E - KU Energy Services/Kentucky Utilities	12,749,748.11	
Fuel		67,711,396.61
Coal 1,448,127.24 Tons @ $46.41; MMBtu 33,090,478.75 @ 203.08¢	67,200,823.21	
Fuel Oil 173,737.49 Gallons @ 269.23¢	467,751.49	
Gas Pipeline 5,200 Mcf @ $8.23	42,821.91	
Plant Materials and Operating Supplies		29,950,707.42
Regular Materials and Supplies	29,475,245.81	
Limestone 55,899.24 Tons @ $8.51	475,461.61	
Stores Expense Undistributed	5,157,847.02	5,157,847.02
Gas Stored Underground - Current		19,007,070.36
Gas Stored Underground* 3,732,244 Mcf (14.73 psia) @ $5.09	19,007,070.36	
Emission Allowances	2,233.53	2,233.53

July 27, 2011

Louisville Gas and Electric Company
Summary Trial Balance
June 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Prepayments		$ 7,798,435.51
Insurance	4,053,780.83	
Taxes	2,386,455.90	
Rights of Way	226,666.71	
Franchises	164,271.66	
Risk Management and Workers Compensation	90,000.00	
Other	877,260.41	
Miscellaneous Current Assets		605,541.52
Derivative Asset - Non-Hedging	605,541.52	
Unamortized Debt Expense		13,247,160.62
Trimble County 2000 Series A due 08/01/30 Var%	738,665.70	
Jefferson County 2001 Series A due 09/01/26 Var%	150,510.54	
Jefferson County 2001 Series A due 09/01/27 Var%	329,678.68	
Jefferson County 2001 Series B due 11/01/27 Var%	179,589.08	
Trimble County 2001 Series A due 09/01/26 Var%	163,648.10	
Trimble County 2001 Series B due 11/01/27 Var%	179,618.54	
Trimble County 2002 Series A due 10/01/32 Var%	790,955.01	
Louisville Metro 2003 Series A Due 10/01/33 1.900%	436,313.66	
Louisville Metro 2007 Series B Due 06/01/33 1.900%	163,814.56	
Trimble County 2007 Series A due 06/01/33 4.600%	1,041,795.86	
First Mortgage Bond due 11/15/15 1.625%	2,136,450.58	
First Mortgage Bond due 11/15/40 5.125%	3,359,910.89	
Revolving Credit Agreement	3,576,209.42	
Unamortized Loss on Bonds	21,328,631.75	21,328,631.75
Accumulated Deferred Income Taxes		55,536,998.05
Federal		
Electric	35,552,740.83	
Gas	10,503,489.54	
State		
Electric	7,539,091.61	
Gas	1,941,676.07	
Regulatory Assets		355,709,240.35
Pension and Postretirement Benefits	213,180,670.00	
2009 Winter Storm	39,819,871.97	
Interest Rate Swap Ineffectiveness	35,068,280.97	
2008 Wind Storm	21,382,468.95	
Deferred Taxes - FAS 109		
Federal		
Electric	12,630,478.54	
State		
Electric	2,303,430.74	
Swap Termination	9,066,459.74	
Asset Retirement Obligations		
Electric	7,864,465.32	
Gas	415,780.40	
Common	5,151.21	
Fuel Adjustment Clause	5,304,000.00	
Gas Supply Clause/PBR	4,761,501.96	
Rate Case Expenses	1,137,111.04	
MISO Exit Fee	1,134,549.90	
KCCS Funding	676,822.89	
EKPC FERC Transmission Costs	452,193.04	
CMRG Funding	203,250.00	
Enviromental Cost Recovery	179,159.00	
General Management Audit	123,594.68	
Other Deferred Debits	1,478,646.74	1,478,646.74
Total Assets	$ 3,496,021,096.49	$ 3,496,021,096.49

* Excludes:

	$	Mcf
Non-recoverable Base Gas	9,648,855.00	7,880,000
Recoverable Base Gas	2,139,990.00	2,930,000
	11,788,845.00	10,810,000

July 27, 2011

Louisville Gas and Electric Company
Summary Trial Balance
June 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 1,352,748,349.62
Common Stock	425,170,424.09	
Less: Common Stock Expense	835,888.64	
Paid-In Capital	83,581,499.00	
Retained Earnings	844,832,315.17	
Pollution Control Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,191,612.46	531,191,612.46
Accounts Payable		85,621,470.31
Regular	81,300,431.64	
Salaries and Wages Accrued	4,397,304.40	
Employee Withholdings Payable	(76,265.73)	
Accounts Payable to Associated Companies		13,004,765.06
LG&E - KU Energy Services/Kentucky Utilities	13,004,765.06	
Customers' Deposits	22,604,581.72	22,604,581.72
Taxes Accrued	10,103,469.64	10,103,469.64
Interest Accrued		5,332,202.80
Jefferson County 2000 Series A due 05/01/27 5.375%	223,958.33	
Trimble County 2000 Series A due 08/01/30 Var%	7,453.85	
Jefferson County 2001 Series A due 09/01/26 Var%	5,825.34	
Jefferson County 2001 Series A due 09/01/27 Var%	84.20	
Jefferson County 2001 Series B due 11/01/27 Var%	7,395.07	
Trimble County 2001 Series A due 09/01/26 Var%	7,232.88	
Trimble County 2001 Series A due 10/01/32 Var%	6,353.63	
Trimble County 2001 Series B due 11/01/27 Var%	6,904.11	
Louisville Metro 2003 Series A due 10/01/33 1.900%	614,755.56	
Louisville Metro 2005 Series A due 02/01/35 5.750%	951,944.44	
Louisville Metro 2007 Series A due 06/01/33 5.625%	145,312.50	
Louisville Metro 2007 Series B due 06/01/33 1.900%	57,591.11	
Trimble County 2007 Series A due 06/01/33 4.600%	230,000.00	
Interest Rate Swaps	655,698.86	
First Mortgage Bond due 11/15/15 1.625%	519,097.23	
First Mortgage Bond due 11/15/40 5.125%	1,866,354.17	
Customers' Deposits	17,368.18	
Other	8,873.34	
Miscellaneous Current and Accrued Liabilities		25,114,319.95
Vacation Pay Accrued	6,718,979.89	
Customer Overpayments	4,984,113.18	
No-Notice Gas Payable	4,828,248.26	
SFAS 133 Derivative Liability	2,854,663.49	
Derivative Liabilities - Non-Hedging	2,414,104.63	
Tax Collections Payable	1,364,781.14	
Unearned Revenue	741,458.25	
Postretirement Benefits - Current	624,694.04	
Other	583,277.07	

Louisville Gas and Electric Company
Summary Trial Balance
June 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Accumulated Deferred Income Taxes		$ 506,075,924.63
Federal		
Electric	367,237,261.05	
Gas	69,898,654.54	
State		
Electric	58,855,264.31	
Gas	10,084,744.73	
Investment Tax Credit		44,135,039.13
Advanced Coal Credit	23,456,603.00	
Job Development Credit		
Electric	20,054,571.98	
Gas	623,864.15	
Regulatory Liabilities		59,639,476.44
Deferred Taxes		
Federal		
Electric	27,289,225.06	
Gas	1,038,846.36	
State		
Electric	15,697,512.72	
Gas	2,373,942.46	
DSM Cost Recovery	6,792,132.51	
Gas Supply Clause/PBR	3,248,899.45	
Asset Retirement Obligations		
Gas	2,139,789.45	
Electric	256,213.72	
MISO Schedule 10 Charges	485,280.06	
Purchased Gas Adjustment - Texas Gas	317,634.65	
Customers' Advances for Construction		8,117,149.39
Line Extensions		
Gas	6,572,117.39	
Electric	784,297.46	
Customer Advances - Museum Plaza	696,187.52	
Other	64,547.02	
Asset Retirement Obligations		52,117,276.38
Electric	34,806,347.41	
Gas	17,205,761.40	
Common	105,167.57	
Other Deferred Credits	21,631,372.89	21,631,372.89
Miscellaneous Long-Term Liabilities		37,441,515.45
Long-Term Derivative Liabilities - SFAS 133	32,213,617.48	
Workers' Compensation	5,227,897.97	
Accumulated Provision for Benefits		146,838,570.62
Postretirement Benefits - SFAS 106	81,709,028.94	
Pension Payable	61,662,688.50	
Post Employment Benefits Payable	3,698,041.00	
Post Employment Medicare Subsidy	(231,187.82)	
Total Liabilities and Stockholders' Equity	$ 3,496,021,096.49	$ 3,496,021,096.49

July 27, 2011

Louisville Gas and Electric Company
Statement of Cash Flows
June 30, 2011

	Year to Date 2011	Year to Date 2010
Cash Flows from Operating Activities		
Net income	$ 59,089,063.21	$ 46,525,705.94
Items not requiring (providing) cash currently:		
Depreciation	70,857,104.22	65,058,284.25
Amortization	3,940,747.27	3,968,065.72
Deferred income taxes - net	30,890,090.70	19,605,517.69
Investment tax credit - net	(1,389,537.00)	(1,250,888.00)
Gain on disposal of assets	(63,747.12)	(1,050.00)
Other	8,323,406.98	22,268,456.52
Change in receivables	47,081,713.91	(24,678,887.04)
Change in inventory	40,583,996.65	27,936,307.24
Change in allowance inventory	495.43	457.44
Change in payables and accrued expenses	(18,316,502.69)	(38,812,389.61)
Change in regulatory assets	(11,672,877.18)	934,926.06
Change in regulatory liabilities	8,213,127.98	(30,276,562.71)
Change in other deferred debits	(16,141,230.82)	1,590.04
Change in other deferred credits	16,031,013.05	13,554,340.97
Pension and postretirement funding	(66,680,000.00)	(22,809,700.00)
Other	3,513,269.66	1,169,727.64
Net cash provided (used) by operating activities	174,260,134.25	83,193,902.15
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(68,990,464.98)	(15,738,309.41)
Gross additions to common utility plant - construction expenditures	(2,897,701.36)	(4,239,650.32)
Proceeds received from sales of property	63,747.12	1,050.00
Change in restricted cash	(3,743,819.21)	-
Change in derivatives	-	203,198.12
Reissuance of reacquired bonds as Available for Sale debt securities	163,200,000.00	
Other	(4,686,871.09)	-
Net cash provided (used) by investing activities	82,944,890.48	(19,773,711.61)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(1,037,658.55)	(26,566.66)
Net change in short-term debt	(174,876,000.00)	(33,042,000.00)
Dividends on common stock	(42,250,000.00)	(30,000,000.00)
Net cash provided (used) by financing activities	(218,163,658.55)	(63,068,566.66)
Net Increase (Decrease) in Cash and Cash Equivalents	39,041,366.18	351,623.88
Cash and Cash Equivalents at Beginning of Period	2,126,011.84	5,195,486.38
Cash and Cash Equivalents at End of Period	$ 41,167,378.02	$ 5,547,110.26

July 27, 2011

Louisville Gas and Electric 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						
Jefferson County 2000 Series A due 05/01/27 5.375%........................	$ 111,979.15	$ 111,979.16	$ 671,875.01	$ 671,874.99	$ 1,343,749.94	$ 1,343,750.01
Trimble County 2000 Series A due 08/01/30 Var%............................	10,046.48	42,361.96	118,972.23	202,561.92	307,691.27	342,657.28
Jefferson County 2001 Series A due 09/01/26 Var%..........................	1,414.56	4,301.22	12,854.40	23,985.78	36,003.75	38,204.54
Jefferson County 2001 Series A due 09/01/27 Var%..........................	12,236.32	12,945.21	128,589.04	72,462.33	245,034.26	170,352.75
Jefferson County 2001 Series B due 11/01/27 Var%..........................	28,886.03	41,175.34	178,976.19	159,667.08	375,814.24	344,783.51
Trimble County 2001 Series A due 09/01/26 Var%............................	7,232.88	13,561.65	55,188.36	86,508.22	133,695.21	211,727.41
Trimble County 2001 Series A due 10/01/32 Var%............................	8,447.15	19,964.95	73,923.96	187,491.74	181,399.11	248,286.13
Trimble County 2001 Series B due 11/01/27 Var%............................	29,054.80	41,041.09	176,294.23	160,616.39	372,227.06	345,732.80
Louisville Metro 2003 Series A due 10/01/33 1.900%........................	202,666.57	-	1,141,688.78	-	1,141,688.78	32,454.36
Louisville Metro 2005 Series A due 02/01/35 5.750%........................	191,666.66	191,666.66	1,149,999.98	1,149,999.99	2,299,999.90	2,300,000.01
Louisville Metro 2007 Series A due 06/01/33 5.625%........................	145,312.49	145,312.49	871,874.94	871,874.99	1,743,749.90	1,743,749.99
Louisville Metro 2007 Series B due 06/01/33 1.900%........................	55,733.35	-	313,964.46	-	313,964.46	-
Trimble County 2007 Series A due 06/01/33 4.600%..........................	230,000.00	230,000.00	1,380,000.00	1,380,000.00	2,760,000.00	2,760,000.00
Interest Rate Swaps...	655,698.88	779,264.88	3,812,093.61	4,099,046.54	7,411,387.38	7,357,398.99
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/15/15 1.625%..	338,541.67	-	2,031,250.00	-	2,539,062.51	-
First Mortgage Bond due 11/15/40 5.125%..	1,217,187.50	-	7,303,125.00	-	9,128,906.25	-
Fidelia/PPL...	-	2,220,150.01	-	13,320,900.02	9,999,675.01	26,641,800.04
Revolving Credit Agreement..	-	-	185,005.01	-	779,683.35	-
Total..	3,246,104.49	3,853,724.62	19,605,675.20	22,386,989.99	41,113,732.38	43,880,897.82
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense...	176,601.37	15,546.83	1,047,079.01	93,138.53	1,407,315.49	186,245.94
Amortization of Loss on Reacquired Debt..	101,002.97	101,002.98	606,017.82	605,232.85	1,212,035.70	1,233,702.48
Total..	277,604.34	116,549.81	1,653,096.83	698,371.38	2,619,351.19	1,419,948.42
Other Interest Charges						
Customers' Deposits..	159,648.67	138,308.08	697,689.78	707,840.77	1,378,755.47	1,501,826.05
Other Tax Deficiencies..	-	7,469.00	-	7,469.00	(24,969.00)	(7,411.00)
Interest on DSM Cost Recovery..	1,630.87	(439.83)	6,195.40	16,859.98	15,750.66	104,268.13
Interest on Debt to Associated Companies..	-	37,766.25	8,862.00	146,314.24	124,969.64	345,992.41
Other Interest Expense...	264,922.58	183,222.92	449,477.12	407,727.01	984,520.28	862,838.08
Total..	426,202.12	366,326.42	1,162,224.30	1,286,211.00	2,479,027.05	2,807,513.67
Total Interest...	$ 3,949,910.95	$ 4,336,600.85	$ 22,420,996.33	$ 24,371,572.37	$ 46,212,110.62	$ 48,108,359.91

July 27, 2011

Louisville Gas and Electric 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..	$ 1,450,538.00	$ 1,222,746.10	$ 8,700,236.00	$ 7,335,243.28
Unemployment..	4,253.00	4,021.39	110,576.37	121,206.87
FICA..	697,401.05	571,985.73	4,038,978.08	3,599,249.35
Public Service Commission Fee.............................	161,096.94	161,675.44	966,581.44	970,052.54
Federal Income..	(6,622,269.54)	(6,229,769.94)	1,206,639.74	10,615,540.90
State Income..	840,976.77	(2,847,086.07)	5,398,308.26	84,218.46
Miscellaneous...	3,281.57	-	26,837.45	20,133.86
Total Charged to Operating Expense..........	(3,464,722.21)	(7,116,427.35)	20,448,157.34	22,745,645.26
Taxes Charged to Other Accounts...........................	982,751.96	10,752,718.59	2,051,461.95	10,147,626.17
Taxes Accrued on Intercompany Accounts.............	(318,747.41)	(238,822.66)	(1,730,146.16)	(1,488,584.16)
Total Taxes Charged...................................	$ (2,800,717.66)	$ 3,397,468.58	$ 20,769,473.13	$ 31,404,687.27

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..	$ 11,354,131.66	$ 8,783,475.25	$ 11,508,999.02	$ 8,628,607.89
Unemployment..	54,386.05	87,546.35	141,169.30	763.10
FICA..	590,648.24	3,254,738.78	3,284,693.88	560,693.14
Federal Income..	(3,741,320.05)	1,303,184.05	(2,438,136.00)	(0.00)
State Income..	229,108.93	5,337,164.38	5,162,379.00	403,894.31
Kentucky Sales and Use Tax..................................	1,088,857.95	1,920,713.74	2,511,954.71	497,616.98
Miscellaneous...	22,339.97	82,650.58	93,096.33	11,894.22
Totals...	$ 9,598,152.75	$ 20,769,473.13	$ 20,264,156.24	$ 10,103,469.64

July 27, 2011

Louisville Gas and Electric Company
Summary of Utility Plant
June 30, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant In Service**						
Common						
Common General Plant	$ 159,884,459.36	$ 5,525,205.81	$ (332,809.01)	$ -	$ 5,192,396.80	$ 165,076,856.16
Common Intangible Plant	56,455,326.72	7,641,723.09	(1,661,801.58)	-	5,979,921.51	62,435,248.23
	216,339,786.08	13,166,928.90	(1,994,610.59)	-	11,172,318.31	227,512,104.39
Electric						
Electric Distribution	927,289,038.50	21,963,024.77	(4,698,575.95)	47,153.43	17,311,602.25	944,600,640.75
Electric General Plant	16,521,615.59	297,947.55	(1,934,885.80)	-	(1,636,938.25)	14,884,677.34
Electric Hydro Production	41,680,209.14	469,609.90	(55,573.58)	-	414,036.32	42,094,245.46
Electric Intangible Plant	2,340.29	-	-	-	-	2,340.29
Electric Other Production	229,401,033.01	1,720,153.61	(150,109.82)	38,429.14	1,608,472.93	231,009,505.94
Electric Steam Production	1,930,347,044.43	196,776,378.30	(9,803,763.30)	4,144,130.56	191,116,745.56	2,121,463,789.99
Electric Transmission	247,742,496.14	1,352,011.90	(521,503.11)	(47,153.43)	783,355.36	248,525,851.50
	3,392,983,777.10	222,579,126.03	(17,164,411.56)	4,182,559.70	209,597,274.17	3,602,581,051.27
Gas						
Gas Distribution	549,799,120.70	30,825,469.15	(466,613.58)	97,729.20	30,456,584.77	580,255,705.47
Gas General Plant	9,178,093.57	351,040.76	(995,401.23)	(97,729.20)	(742,089.67)	8,436,003.90
Gas Intangible Plant	1,187.49	-	-	-	-	1,187.49
Gas Storage	78,415,311.06	1,806,296.22	(1,395,336.80)	-	410,959.42	78,826,270.48
Gas Transmission	16,661,869.68	142,121.04	(531.82)	-	141,589.22	16,803,458.90
	654,055,582.50	33,124,927.17	(2,857,883.43)	-	30,267,043.74	684,322,626.24
Total 101 Accounts	4,263,379,145.68	268,870,982.10	(22,016,905.58)	4,182,559.70	251,036,636.22	4,514,415,781.90
105 **Plant Held For Future Use**						
Electric						
Electric Distribution	649,014.48	-	-	-	-	649,014.48
Electric Steam Production	4,182,559.70	-	-	(4,182,559.70)	(4,182,559.70)	-
	4,831,574.18	-	-	(4,182,559.70)	(4,182,559.70)	649,014.48
Total 105001	$ 4,831,574.18	$ -	$ -	$ (4,182,559.70)	$ (4,182,559.70)	$ 649,014.48

July 27, 2011

Louisville Gas and Electric Company
Summary of Utility Plant
June 30, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
106 **Completed Construction Not Classified**						
Common						
Common General Plant..........	$ 597,158.63	$ 3,248,252.62	$ -	$ -	$ 3,248,252.62	$ 3,845,411.25
Common Intangible Plant..........	2,714,931.36	(1,577,400.79)	-	-	(1,577,400.79)	1,137,530.57
	3,312,089.99	1,670,851.83	-	-	1,670,851.83	4,982,941.82
Electric						
Electric Distribution..........	11,544,733.90	6,468,177.59	-	-	6,468,177.59	18,012,911.49
Electric General Plant..........	50,763.87	203,596.76	-	-	203,596.76	254,360.63
Electric Hydro Production..........	16,952.26	427,866.66	-	-	427,866.66	444,818.92
Electric Intangible Plant..........	-	-	-	-	-	-
Electric Other Production..........	1,767,208.21	(139,004.50)	-	-	(139,004.50)	1,628,203.71
Electric Steam Production..........	15,929,229.77	4,990,217.60	-	-	4,990,217.60	20,919,447.37
Electric Transmission..........	35,045,472.82	4,623,888.19	-	-	4,623,888.19	39,669,361.01
	64,354,360.83	16,574,742.30	-	-	16,574,742.30	80,929,103.13
Gas						
Gas Distribution..........	24,420,156.16	(9,853,746.00)	-	-	(9,853,746.00)	14,566,410.16
Gas General Plant..........	126,992.17	74,776.30	-	-	74,776.30	201,768.47
Gas Intangible Plant..........	-	-	-	-	-	-
Gas Storage..........	951,426.06	88,965.93	-	-	88,965.93	1,040,391.99
Gas Transmission..........	-	1,967,913.07	-	-	1,967,913.07	1,967,913.07
	25,498,574.39	(7,722,090.70)	-	-	(7,722,090.70)	17,776,483.69
Total 106 Accounts..........	93,165,025.21	10,523,503.43	-	-	10,523,503.43	103,688,528.64
117 **Gas Stored Underground-Noncurrent**						
Gas						
Gas Stored Nonrecoverable..........	2,139,990.00	-	-	-	-	2,139,990.00
	2,139,990.00	-	-	-	-	2,139,990.00
Total 117001..........	2,139,990.00	-	-	-	-	2,139,990.00
121 **Nonutility Property**						
Common						
Non Utility Property..........	75,239.56	-	-	-	-	75,239.56
	75,239.56	-	-	-	-	75,239.56
Total 121001..........	75,239.56	-	-	-	-	75,239.56
107 **Construction Work In Progress**						
Common..........	21,243,879.89	(11,940,079.37)	-	-	(11,940,079.37)	9,303,800.52
Electric..........	324,323,732.14	(186,160,270.40)	-	-	(186,160,270.40)	138,163,461.74
Gas..........	39,756,306.91	(5,768,571.03)	-	-	(5,768,571.03)	33,987,735.88
	385,323,918.94	(203,868,920.80)	-	-	(203,868,920.80)	181,454,998.14
Total Plant (Non-CWIP)..........	4,363,590,974.63	279,394,485.53	(22,016,905.58)	-	257,377,579.95	4,620,968,554.58
Total Plant + CWIP..........	4,748,914,893.57	75,525,564.73	(22,016,905.58)	-	53,508,659.15	4,802,423,552.72
Total Plant + CWIP - Non Utility..........	$ 4,748,839,654.01	$ 75,525,564.73	$ (22,016,905.58)	$ -	$ 53,508,659.15	$ 4,802,348,313.16

July 27, 2011

Louisville Gas and Electric 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										
Common General Plant	$ (77,263,235.10)	$ (6,305,473.03)	$ 332,809.01	$ -	$ -	$ -	$ -	$ -	$ -	$ (83,235,899.12)
Common General Plant - ARO	(343.19)	(1,030.20)	-	-	-	-	-	-	-	(1,373.39)
Electric Distribution	(277,000,365.75)	(8,632,718.81)	4,698,575.95	(382.60)	-	-	-	-	-	(280,934,891.21)
Electric Distribution - ARO	(1,256.54)	(3,016.93)	-	-	-	-	-	-	-	(4,273.47)
Electric General Plant	(12,910,034.19)	(177,265.38)	1,934,885.80	-	-	-	-	-	-	(11,152,413.77)
Electric Hydro Production	(9,718,276.66)	(279,470.04)	55,573.58	-	-	-	-	-	-	(9,942,173.12)
Electric Hydro Production - ARO	(364.10)	(874.26)	-	-	-	-	-	-	-	(1,238.36)
Electric Other Production	(60,282,055.17)	(4,088,739.72)	150,109.82	-	-	-	-	-	-	(64,220,685.07)
Electric Other Production - ARO	(192.68)	(530.78)	-	-	-	-	-	-	-	(723.46)
Electric Steam Production	(1,029,518,070.37)	(28,290,839.23)	9,155,074.64	-	-	-	-	-	-	(1,048,653,834.96)
Electric Steam Production - ARO	(204,061.94)	(1,247,646.43)	648,688.66	-	-	-	-	-	-	(803,019.71)
Electric Transmission	(119,192,606.75)	(2,184,555.52)	521,503.11	382.60	-	-	-	-	-	(120,855,276.56)
Electric Transmission - ARO	(41.40)	(99.42)	-	-	-	-	-	-	-	(140.82)
Gas Distribution	(125,049,477.23)	(5,721,434.96)	391,574.31	(13,332.40)	-	-	-	-	-	(130,392,670.28)
Gas Distribution - ARO	(49,734.93)	(223,200.28)	75,039.27	-	-	-	-	-	-	(197,895.94)
Gas General Plant	(6,299,629.20)	(149,726.54)	995,401.23	13,332.40	-	-	-	-	-	(5,440,622.11)
Gas Storage	(31,288,281.49)	(539,990.76)	999,931.34	-	-	-	-	-	-	(30,828,340.91)
Gas Storage - ARO	(39,466.10)	(503,399.89)	395,405.46	-	-	-	-	-	-	(147,460.53)
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(9,448,605.32)	(27,866.83)	531.82	-	-	-	-	-	-	(9,475,940.33)
Non Utility Property	(63,360.36)	-	-	-	-	-	-	-	-	(63,360.36)
	(1,758,329,458.47)	(58,377,879.01)	20,355,104.00	0.00	-	-	-	-	-	(1,796,352,233.48)
Cost Of Removal										
Common General Plant	(688,372.47)	(138,833.55)	-	-	-	-	103,898.11	-	-	(723,307.91)
Electric Distribution	(146,715,298.78)	(3,418,304.24)	-	(55.48)	-	-	2,420,815.50	-	-	(147,712,843.00)
Electric General Plant	3,866.64	-	-	-	-	-	-	-	-	3,866.64
Electric Hydro Production	736,907.70	(21,233.76)	-	-	-	-	34,591.42	-	-	750,265.36
Electric Other Production	(2,505,175.99)	(175,587.66)	-	-	-	-	104,342.09	-	-	(2,576,421.56)
Electric Steam Production	(94,783,295.15)	(8,445,071.26)	-	-	-	-	2,304,863.79	-	-	(100,923,502.62)
Electric Transmission	(24,538,454.78)	(703,297.62)	-	55.48	-	-	(70,121.47)	-	-	(25,311,818.39)
Gas Distribution	(60,212,131.14)	(1,613,746.91)	-	-	-	-	1,339,985.07	-	-	(60,485,892.98)
Gas General Plant	(0.02)	-	-	-	-	-	-	-	-	(0.02)
Gas Storage	(170,437.90)	(69,904.37)	-	-	-	-	561,876.02	-	-	321,533.75
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(3,016,813.95)	(6,892.24)	-	-	-	-	32,210.90	-	-	(2,991,495.29)
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	$ (331,889,205.84)	$ (14,592,871.61)	$ -	$ -	$ -	$ -	$ 6,832,461.43	$ -	$ -	$ (339,649,616.02)

July 27, 2011

Louisville Gas and Electric 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
Salvage										
Common General Plant	$ 278,074.55	$ 191.64	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 278,266.19
Electric Distribution	17,535,024.98	692,169.05	-	-	-	-	-	(182,166.06)	-	18,045,027.97
Electric General Plant	138,281.25	1,155.30	-	-	-	-	-	-	-	139,436.55
Electric Hydro Production	376,638.17	-	-	-	-	-	-	-	-	376,638.17
Electric Other Production	(18,998.67)	-	-	-	-	-	-	-	-	(18,998.67)
Electric Steam Production	22,028,570.14	1,008,862.73	-	-	-	-	-	(26,976.51)	-	23,010,456.36
Electric Transmission	6,247,368.67	130,306.68	-	-	-	-	-	-	-	6,377,675.35
Gas Distribution	3,594,440.75	98,666.94	-	-	-	-	-	-	-	3,693,107.69
Gas General Plant	225,788.37	1,074.79	-	-	-	-	-	-	-	226,863.16
Gas Storage	269,933.04	8,553.93	-	-	-	-	-	-	-	278,486.97
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	217,923.11	2,584.59	-	-	-	-	-	-	-	220,507.70
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	50,893,044.36	1,943,565.65	-	-	-	-	-	(209,142.57)	-	52,627,467.44
Total Reserves										
Common	(77,737,236.57)	(6,445,145.14)	332,809.01	-	-	-	103,898.11	-	-	(83,745,674.59)
Electric	(1,730,321,891.37)	(55,836,757.30)	17,164,411.56	-	-	-	4,794,491.33	(209,142.57)	-	(1,764,408,888.35)
Gas	(231,266,492.01)	(8,745,282.53)	2,857,883.43	-	-	-	1,934,071.99	-	-	(235,219,819.12)
	(2,039,325,619.95)	(71,027,184.97)	20,355,104.00	-	-	-	6,832,461.43	(209,142.57)	-	(2,083,374,382.06)
Retirement Work In Progress										
Common	342,947.00	-	-	162,020.85	-	(103,898.11)	(5,795.69)	(17,894.00)	-	377,380.05
Electric	9,603,653.21	-	-	(35,892.93)	(803,385.38)	(4,350,208.62)	3,900,143.93	(224,512.58)	(58,937.48)	8,030,860.15
Gas	2,523,160.64	-	-	(66,835.06)	(1,053,809.06)	(1,138,268.27)	736,916.65	(3,332.90)	(2,374.27)	995,457.73
	12,469,760.85	-	-	59,292.86	(1,857,194.44)	(5,592,375.00)	4,631,264.89	(245,739.48)	(61,311.75)	9,403,697.93
YTD ACTIVITY	(2,026,855,859.10)	(71,027,184.97)	20,355,104.00	59,292.86	(1,857,194.44)	(5,592,375.00)	11,463,726.32	(454,882.05)	(61,311.75)	(2,073,970,684.13)
Amortization										
Common	(16,306,390.60)	(3,940,747.27)	1,661,801.58	-	-	-	-	-	-	(18,585,336.29)
Electric	(100.00)	-	-	-	-	-	-	-	-	(100.00)
Gas	(800.00)	-	-	-	-	-	-	-	-	(800.00)
AMORTIZATION TOTAL	(16,307,290.60)	(3,940,747.27)	1,661,801.58	-	-	-	-	-	-	(18,586,236.29)
Depreciation & Amortization Total	$ (2,043,163,149.70)	$ (74,967,932.24)	$ 22,016,905.58	$ 59,292.86	$ (1,857,194.44)	$ (5,592,375.00)	$ 11,463,726.32	$ (454,882.05)	$ (61,311.75)	$ (2,092,556,920.42)
Depr & Amort - Nonutility for Balance Sheet										(2,092,493,560.06)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)	$ 2,705,739,864.67									$ 2,709,854,753.10

July 27, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
June 30, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 95,926,278.08	$ -	$ 95,926,278.08
Gas Operating Revenues	11,394,622.50	-	11,394,622.50
Total Operating Revenues	107,320,900.58	-	107,320,900.58
Fuel for Electric Generation	29,573,632.96	-	29,573,632.96
Power Purchased	6,493,106.90	-	6,493,106.90
Gas Supply Expenses	4,073,116.36	-	4,073,116.36
Other Operation Expenses	20,233,157.90	-	20,233,157.90
Maintenance	10,121,123.40	-	10,121,123.40
Depreciation	11,775,559.24	(0.02)	11,775,559.22
Amortization Expense	684,362.07	-	684,362.07
Regulatory Credits	(359,386.42)	-	(359,386.42)
Taxes			
Federal Income	(6,622,269.54)	-	(6,622,269.54)
State Income	840,976.77	-	840,976.77
Deferred Federal Income - Net	12,018,131.58	8,230.83	12,026,362.41
Deferred State Income - Net	44,957.43	1,501.08	46,458.51
Property and Other	2,316,570.56	-	2,316,570.56
Investment Tax Credit	-	-	-
Amortization of Investment Tax Credit	(236,034.00)	-	(236,034.00)
Loss (Gain) from Disposition of Allowances	-	-	-
Accretion Expense	215,040.82	-	215,040.82
Total Operating Expenses	91,172,046.03	9,731.89	91,181,777.92
Net Operating Income	16,148,854.55	(9,731.89)	16,139,122.66
Other Income Less Deductions	829,607.98	-	829,607.98
Income Before Interest Charges	16,978,462.53	(9,731.89)	16,968,730.64
Interest on Long-Term Debt	3,246,104.49	(25,017.63)	3,221,086.86
Amortization of Debt Expense - Net	277,604.34	-	277,604.34
Other Interest Expenses	426,202.12	-	426,202.12
Total Interest Charges	3,949,910.95	(25,017.63)	3,924,893.32
Net Income	$ 13,028,551.58	$ 15,285.74	$ 13,043,837.32

Note: Purchase accounting is subject to change through October 31, 2011

July 27, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
June 30, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 508,443,709.65	$ -	$ 508,443,709.65
Gas Operating Revenues	183,302,508.15	-	183,302,508.15
Total Operating Revenues	691,746,217.80	-	691,746,217.80
Fuel for Electric Generation	172,372,936.75	-	172,372,936.75
Power Purchased	37,431,997.58	-	37,431,997.58
Gas Supply Expenses	104,115,251.58	-	104,115,251.58
Other Operation Expenses	116,766,857.69	27,884.66	116,794,742.35
Maintenance	58,722,647.11	-	58,722,647.11
Depreciation	70,857,104.22	-	70,857,104.22
Amortization Expense	3,940,747.27	-	3,940,747.27
Regulatory Credits	(3,295,943.40)	-	(3,295,943.40)
Taxes			
Federal Income	1,206,639.74	-	1,206,639.74
State Income	5,398,308.26	-	5,398,308.26
Deferred Federal Income - Net	29,108,145.53	40,210.77	29,148,356.30
Deferred State Income - Net	(221,983.14)	7,333.29	(214,649.85)
Property and Other	13,843,209.34	-	13,843,209.34
Investment Tax Credit	-	-	-
Amortization of Investment Tax Credit	(1,389,537.00)	-	(1,389,537.00)
Loss (Gain) from Disposition of Allowances	(2,577.94)	-	(2,577.94)
Accretion Expense	1,316,145.21	-	1,316,145.21
Total Operating Expenses	610,169,948.80	75,428.72	610,245,377.52
Net Operating Income	81,576,269.00	(75,428.72)	81,500,840.28
Other Income Less Deductions	(66,209.46)	-	(66,209.46)
Income Before Interest Charges	81,510,059.54	(75,428.72)	81,434,630.82
Interest on Long-Term Debt	19,605,675.20	(150,105.78)	19,455,569.42
Amortization of Debt Expense - Net	1,653,096.83	-	1,653,096.83
Other Interest Expenses	1,162,224.30	-	1,162,224.30
Total Interest Charges	22,420,996.33	(150,105.78)	22,270,890.55
Net Income	$ 59,089,063.21	$ 74,677.06	$ 59,163,740.27

Note: Purchase accounting is subject to change through October 31, 2011

July 27, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
June 30, 2011

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period…………………………….	$ 831,803,763.59	$ 759,575,375.78	$ (808,839,891.12)	$ -	$ 22,963,872.47	$ 759,575,375.78
Add:						
Net Income (Loss) for Period………………………….	13,028,551.58	12,229,196.40	15,285.74	-	13,043,837.32	12,229,196.40
Deduct:						
Adjustment to Retained Earnings…………………….	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	-	-	-	-	-	-
Balance at End of Period………………………………….	$ 844,832,315.17	$ 771,804,572.18	$ (808,824,605.38)	$ -	$ 36,007,709.79	$ 771,804,572.18

Note: Purchase accounting is subject to change through October 31, 2011

July 27, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
June 30, 2011

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……………………………	$ 827,993,251.96	$ 755,278,866.24	$ (808,899,282.44)	$ -	$ 19,093,969.52	$ 755,278,866.24
Add:						
Net Income (Loss) for Period…………………………	59,089,063.21	46,525,705.94	74,677.06	-	59,163,740.27	46,525,705.94
Deduct:						
Adjustment to Retained Earnings……………………	-	-		-	-	-
Common Dividends						
Common Stock Without Par Value………………	42,250,000.00	30,000,000.00	-	-	42,250,000.00	30,000,000.00
Balance at End of Period……………………………………	$ 844,832,315.17	$ 771,804,572.18	$ (808,824,605.38)	$ -	$ 36,007,709.79	$ 771,804,572.18

Note: Purchase accounting is subject to change through October 31, 2011

July 27, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
June 30, 2011

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……	$ 771,804,572.18	$ 686,162,111.03	$ -	$ -	$ 771,804,572.18	$ 686,162,111.03
Add:						
Net Income (Loss) for Period……	140,277,742.99	115,642,461.15	122,286.14	-	140,400,029.13	115,642,461.15
Deduct:						
Adjustment to Retained Earnings……	-	-	808,946,891.52	-	808,946,891.52	-
Common Dividends						
Common Stock Without Par Value……	67,250,000.00	30,000,000.00	-	-	67,250,000.00	30,000,000.00
Balance at End of Period……	$ 844,832,315.17	$ 771,804,572.18	$ (808,824,605.38)	$ -	$ 36,007,709.79	$ 771,804,572.18

Note: Purchase accounting is subject to change through October 31, 2011

July 27, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of June 30, 2011

Assets	Without Purchase Accounting	Purchase Accounting	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 4,802,348,313.16	$ -	$ 4,802,348,313.16
Less: Reserves for Depreciation and Amortization....	2,092,493,560.06	-	2,092,493,560.06
Total..	2,709,854,753.10	-	2,709,854,753.10
Investments			
Ohio Valley Electric Corporation.............................	594,286.00	-	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	-	11,879.20
Special Funds...	22,505,965.16	-	22,505,965.16
Total..	23,112,130.36	-	23,112,130.36
Current and Accrued Assets			
Cash..	41,156,614.54	-	41,156,614.54
Special Deposits..	4,626,601.12	-	4,626,601.12
Temporary Cash Investments...................................	10,763.48	-	10,763.48
Accounts Receivable - Less Reserve.........................	126,976,576.30	-	126,976,576.30
Accounts Receivable from Associated Companies....	12,749,748.11	-	12,749,748.11
Materials and Supplies - At Average Cost			
Fuel..	67,711,396.61	-	67,711,396.61
Plant Materials and Operating Supplies.................	29,950,707.42	-	29,950,707.42
Stores Expense...	5,157,847.02	-	5,157,847.02
Gas Stored Underground.......................................	19,007,070.36	-	19,007,070.36
Emission Allowances...	2,233.53	-	2,233.53
Prepayments..	7,798,435.51	-	7,798,435.51
Miscellaneous Current and Accrued Assets..............	605,541.52	-	605,541.52
Total..	315,753,535.52	-	315,753,535.52
Deferred Debits and Other			
Unamortized Debt Expense......................................	13,247,160.62	(3,574,461.51)	9,672,699.11
Unamortized Loss on Bonds....................................	21,328,631.75	-	21,328,631.75
Accumulated Deferred Income Taxes.......................	55,536,998.05	77,778,242.30	133,315,240.35
Deferred Regulatory Assets.....................................	355,709,240.35	11,331,282.96	367,040,523.31
Other Deferred Debits..	1,478,646.74	185,810,670.12	187,289,316.86
Goodwill..	-	389,157,351.59	389,157,351.59
Total..	447,300,677.51	660,503,085.46	1,107,803,762.97
Total Assets..	$ 3,496,021,096.49	$ 660,503,085.46	$ 4,156,524,181.95

Note: Purchase accounting is subject to change through October 31, 2011

July 27, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of June 30, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting	Total
Proprietary Capital			
Common Stock..	$ 425,170,424.09	$ -	$ 425,170,424.09
Less: Common Stock Expense......................................	835,888.64	-	835,888.64
Paid-In Capital..	83,581,499.00	1,194,085,869.02	1,277,667,368.02
Other Comprehensive Income......................................	-	-	-
Retained Earnings...	844,832,315.17	(808,824,605.38)	36,007,709.79
Total Proprietary Capital..	1,352,748,349.62	385,261,263.64	1,738,009,613.26
Pollution Control Bonds - Net of Reacquired Bonds....	574,304,000.00	6,376,575.96	580,680,575.96
First Mortgage Bonds..	531,191,612.46	-	531,191,612.46
LT Notes Payable to Associated Companies................	-	-	-
Total Long-Term Debt..	1,105,495,612.46	6,376,575.96	1,111,872,188.42
Total Capitalization..	2,458,243,962.08	391,637,839.60	2,849,881,801.68
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Accounts Payable..	85,621,470.31	-	85,621,470.31
Accounts Payable to Associated Companies................	13,004,765.06	-	13,004,765.06
Customer Deposits..	22,604,581.72	-	22,604,581.72
Taxes Accrued..	10,103,469.64	-	10,103,469.64
Dividends Declared..	-	-	-
Interest Accrued..	5,332,202.80	-	5,332,202.80
Miscellaneous Current and Accrued Liabilities...........	25,114,319.95	-	25,114,319.95
Total..	161,780,809.48	-	161,780,809.48
Deferred Credits and Other			
Accumulated Deferred Income Taxes..........................	506,075,924.63	75,297,754.29	581,373,678.92
Investment Tax Credit..	44,135,039.13	-	44,135,039.13
Regulatory Liabilities...	59,639,476.44	185,810,670.12	245,450,146.56
Customer Advances for Construction...........................	8,117,149.39	-	8,117,149.39
Asset Retirement Obligations.......................................	52,117,276.38	-	52,117,276.38
Other Deferred Credits...	21,631,372.89	7,756,821.45	29,388,194.34
Miscellaneous Long-Term Liabilities...........................	37,441,515.45	-	37,441,515.45
Misc Long-Term Liab Due to Assoc Cos......................	-	-	-
Accum Provision for Postretirement Benefits..............	146,838,570.62	-	146,838,570.62
Total..	875,996,324.93	268,865,245.86	1,144,861,570.79
Total Liabilities and Stockholders' Equity.........................	$ 3,496,021,096.49	$ 660,503,085.46	$ 4,156,524,181.95

Note: Purchase accounting is subject to change through October 31, 2011

July 27, 2011

LOUISVILLE GAS AND ELECTRIC COMPANY

Financial Reports

May 31, 2011

Index
Financial and Operating Reports

Louisville Gas and Electric 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.

Louisville Gas and Electric Company
Comparative Statement of Income
May 31, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 82,342,454.95	$ 80,095,089.99	$ 2,247,364.96	2.81
Gas Operating Revenues...	15,822,650.10	11,310,812.08	4,511,838.02	39.89
Total Operating Revenues...	98,165,105.05	91,405,902.07	6,759,202.98	7.39
Fuel for Electric Generation..	27,927,729.83	29,647,940.03	(1,720,210.20)	(5.80)
Power Purchased..	6,396,864.92	4,606,491.86	1,790,373.06	38.87
Gas Supply Expenses..	7,748,745.56	4,577,833.85	3,170,911.71	69.27
Other Operation Expenses..	20,079,042.25	19,098,593.27	980,448.98	5.13
Maintenance..	9,772,439.82	8,874,273.59	898,166.23	10.12
Depreciation..	12,745,145.63	10,899,067.44	1,846,078.19	16.94
Amortization Expense...	669,166.96	611,095.34	58,071.62	9.50
Regulatory Credits..	(1,366,601.03)	(182,520.73)	(1,184,080.30)	(648.74)
Taxes				
Federal Income..	88,889.98	2,343,232.70	(2,254,342.72)	(96.21)
State Income...	1,087,945.48	427,337.27	660,608.21	154.59
Deferred Federal Income - Net.................................	3,431,528.62	-	3,431,528.62	100.00
Deferred State Income - Net......................................	(608,867.93)	-	(608,867.93)	100.00
Property and Other..	2,326,799.92	1,930,582.86	396,217.06	20.52
Investment Tax Credit...	-	-	-	-
Amortization of Investment Tax Credit.....................	(236,034.00)	(208,481.00)	(27,553.00)	(13.22)
Loss (Gain) from Disposition of Allowances...............	-	-	-	-
Accretion Expense..	220,800.15	167,880.99	52,919.16	31.52
Total Operating Expenses...	90,283,596.16	82,793,327.47	7,490,268.69	9.05
Net Operating Income..	7,881,508.89	8,612,574.60	(731,065.71)	(8.49)
Other Income Less Deductions.................................	252,722.76	(2,112,116.09)	2,364,838.85	111.97
Income Before Interest Charges................................	8,134,231.65	6,500,458.51	1,633,773.14	25.13
Interest on Long-Term Debt..	3,220,360.74	3,757,723.05	(537,362.31)	(14.30)
Amortization of Debt Expense - Net............................	276,853.27	116,383.02	160,470.25	137.88
Other Interest Expenses...	155,450.41	178,038.65	(22,588.24)	(12.69)
Total Interest Charges...	3,652,664.42	4,052,144.72	(399,480.30)	(9.86)
Net Income..	$ 4,481,567.23	$ 2,448,313.79	$ 2,033,253.44	83.05

June 21, 2011

Louisville Gas and Electric Company
Comparative Statement of Income
May 31, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 412,517,431.57	$ 380,086,645.43	$ 32,430,786.14	8.53
Gas Operating Revenues...	171,907,885.65	160,511,271.94	11,396,613.71	7.10
Total Operating Revenues...	584,425,317.22	540,597,917.37	43,827,399.85	8.11
Fuel for Electric Generation..	142,799,303.79	140,355,237.47	2,444,066.32	1.74
Power Purchased..	30,938,890.68	24,706,763.93	6,232,126.75	25.22
Gas Supply Expenses..	100,042,135.22	92,637,161.10	7,404,974.12	7.99
Other Operation Expenses..	96,533,699.79	91,708,703.28	4,824,996.51	5.26
Maintenance...	48,601,523.71	45,200,644.50	3,400,879.21	7.52
Depreciation...	59,081,544.98	54,126,693.55	4,954,851.43	9.15
Amortization Expense...	3,256,385.20	3,351,957.99	(95,572.79)	(2.85)
Regulatory Credits...	(2,936,556.98)	(904,289.05)	(2,032,267.93)	(224.74)
Taxes				
Federal Income..	7,828,909.28	16,845,310.84	(9,016,401.56)	(53.52)
State Income...	4,557,331.49	2,931,304.53	1,626,026.96	55.47
Deferred Federal Income - Net.................................	17,090,013.95	1,920,879.99	15,169,133.96	789.70
Deferred State Income - Net......................................	(266,940.57)	400,912.77	(667,853.34)	(166.58)
Property and Other..	11,526,638.78	10,085,457.24	1,441,181.54	14.29
Investment Tax Credit...	-	-	-	-
Amortization of Investment Tax Credit.....................	(1,153,503.00)	(1,042,407.00)	(111,096.00)	(10.66)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense...	1,101,104.39	831,090.29	270,014.10	32.49
Total Operating Expenses...	518,997,902.77	483,120,961.29	35,876,941.48	7.43
Net Operating Income..	65,427,414.45	57,476,956.08	7,950,458.37	13.83
Other Income Less Deductions.................................	(895,817.44)	(3,145,475.02)	2,249,657.58	71.52
Income Before Interest Charges................................	64,531,597.01	54,331,481.06	10,200,115.95	18.77
Interest on Long-Term Debt...	16,359,570.71	18,533,265.37	(2,173,694.66)	(11.73)
Amortization of Debt Expense - Net............................	1,375,492.49	581,821.57	793,670.92	136.41
Other Interest Expenses..	736,022.18	919,884.58	(183,862.40)	(19.99)
Total Interest Charges...	18,471,085.38	20,034,971.52	(1,563,886.14)	(7.81)
Net Income...	$ 46,060,511.63	$ 34,296,509.54	$ 11,764,002.09	34.30

June 21, 2011

Louisville Gas and Electric Company
Comparative Statement of Income
May 31, 2011

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 1,048,042,353.11	$ 930,862,934.88	$ 117,179,418.23	12.59
Gas Operating Revenues...	314,343,969.59	285,184,559.94	29,159,409.65	10.22
Total Operating Revenues...	1,362,386,322.70	1,216,047,494.82	146,338,827.88	12.03
Fuel for Electric Generation...	371,000,392.66	323,710,038.25	47,290,354.41	14.61
Power Purchased...	60,611,845.44	53,881,972.11	6,729,873.33	12.49
Gas Supply Expenses...	176,408,582.17	162,402,312.32	14,006,269.85	8.62
Other Operation Expenses..	231,638,001.08	219,687,525.74	11,950,475.34	5.44
Maintenance...	115,101,984.29	64,036,699.45	51,065,284.84	79.74
Depreciation...	136,164,854.70	129,861,655.16	6,303,199.54	4.85
Amortization Expense...	7,631,416.11	8,420,180.02	(788,763.91)	(9.37)
Regulatory Credits..	(6,301,999.38)	(2,170,380.87)	(4,131,618.51)	(190.36)
Taxes				
Federal Income..	19,858,205.62	45,782,291.05	(25,924,085.43)	(56.62)
State Income...	7,673,194.39	7,261,374.75	411,819.64	5.67
Deferred Federal Income - Net.................................	42,836,138.96	8,709,868.00	34,126,270.96	391.81
Deferred State Income - Net......................................	1,702,171.10	2,151,974.66	(449,803.56)	(20.90)
Property and Other..	24,012,805.36	22,386,613.86	1,626,191.50	7.26
Investment Tax Credit...	-	2,737,009.49	(2,737,009.49)	(100.00)
Amortization of Investment Tax Credit.....................	(2,612,870.00)	(2,812,847.28)	199,977.28	7.11
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	3,554,119.73	1,982,427.65	1,571,692.08	79.28
Total Operating Expenses...	1,189,276,264.29	1,047,994,254.22	141,282,010.07	13.48
Net Operating Income..	173,110,058.41	168,053,240.60	5,056,817.81	3.01
Other Income Less Deductions.................................	12,967,129.92	(800,649.28)	13,767,779.20	1,719.58
Income Before Interest Charges................................	186,077,188.33	167,252,591.32	18,824,597.01	11.26
Interest on Long-Term Debt...	41,721,352.51	43,704,765.67	(1,983,413.16)	(4.54)
Amortization of Debt Expense - Net............................	2,458,296.66	1,427,631.30	1,030,665.36	72.19
Other Interest Expenses..	2,419,151.35	2,666,606.85	(247,455.50)	(9.28)
Total Interest Charges...	46,598,800.52	47,799,003.82	(1,200,203.30)	(2.51)
Net Income...	$ 139,478,387.81	$ 119,453,587.50	$ 20,024,800.31	16.76

June 21, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings
May 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period..	$ 852,322,196.36	$ 757,127,061.99	$ 827,993,251.96	$ 755,278,866.24	$ 759,575,375.78	$ 715,121,788.28
Add:						
Net Income for Period..	4,481,567.23	2,448,313.79	46,060,511.63	34,296,509.54	139,478,387.81	119,453,587.50
Deduct:						
Common Dividends						
Common Stock Without Par Value.....................	25,000,000.00	-	42,250,000.00	30,000,000.00	67,250,000.00	75,000,000.00
Balance at End of Period...	$ 831,803,763.59	$ 759,575,375.78	$ 831,803,763.59	$ 759,575,375.78	$ 831,803,763.59	$ 759,575,375.78

June 21, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of May 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,792,382,669.03	$ 4,576,411,472.76
Less: Reserves for Depreciation and Amortization	2,086,932,887.81	2,001,192,563.45
Total	2,705,449,781.22	2,575,218,909.31
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	21,674,314.80	16,102,047.29
Total	22,280,480.00	16,708,212.49
Current and Accrued Assets		
Cash	42,642,184.10	4,093,386.56
Special Deposits	6,103,356.02	755,688.09
Temporary Cash Investments	16,607,994.23	119.71
Accounts Receivable - Less Reserve	117,302,831.48	122,964,056.28
Accounts Receivable from Associated Companies	17,220,727.53	13,089,862.47
Materials and Supplies - At Average Cost		
Fuel	64,042,394.78	74,024,035.18
Plant Materials and Operating Supplies	29,638,442.60	29,814,569.11
Stores Expense	5,123,126.75	4,770,116.70
Gas Stored Underground	12,379,663.46	10,720,154.28
Emission Allowances	2,331.27	3,823.11
Prepayments	6,486,268.51	5,557,672.61
Miscellaneous Current and Accrued Assets	681,197.76	2,805,844.80
Total	318,230,518.49	268,599,328.90
Deferred Debits and Other		
Unamortized Debt Expense	13,330,061.12	3,776,570.04
Unamortized Loss on Bonds	21,429,634.70	22,641,670.10
Accumulated Deferred Income Taxes	55,739,575.24	52,035,131.46
Deferred Regulatory Assets	358,597,038.27	320,150,845.07
Other Deferred Debits	1,033,868.72	1,356,503.81
Total	450,130,178.05	399,960,720.48
Total Assets	$ 3,496,090,957.76	$ 3,260,487,171.18

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	(11,313,632.31)
Retained Earnings	831,803,763.59	759,575,375.78
Total Proprietary Capital	1,339,719,798.04	1,256,177,777.92
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	411,104,000.00
First Mortgage Bonds	531,168,290.80	-
LT Notes Payable to Associated Companies	-	485,000,000.00
Total Long-Term Debt	1,105,472,290.80	896,104,000.00
Total Capitalization	2,445,192,088.84	2,152,281,777.92
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	140,750,400.00
Accounts Payable	83,744,950.28	76,031,950.00
Accounts Payable to Associated Companies	13,185,424.92	15,645,927.12
Customer Deposits	22,522,323.63	24,161,270.63
Taxes Accrued	10,625,328.89	16,134,690.53
Interest Accrued	6,438,420.39	4,194,617.12
Dividends Declared	25,000,000.00	-
Miscellaneous Current and Accrued Liabilities	28,264,294.97	23,498,823.08
Total	189,780,743.08	300,417,678.48
Deferred Credits and Other		
Accumulated Deferred Income Taxes	492,983,143.27	425,917,166.76
Investment Tax Credit	44,371,073.13	46,983,943.13
Regulatory Liabilities	59,210,182.72	54,737,886.15
Customer Advances for Construction	8,092,132.24	9,284,085.81
Asset Retirement Obligations	51,902,235.56	33,874,719.43
Other Deferred Credits	18,472,668.22	18,309,202.24
Miscellaneous Long-Term Liabilities	39,234,121.95	40,012,260.16
Accum Provision for Postretirement Benefits	146,852,568.75	178,668,451.10
Total	861,118,125.84	807,787,714.78
Total Liabilities and Stockholders' Equity	$ 3,496,090,957.76	$ 3,260,487,171.18

June 21, 2011

Louisville Gas and Electric 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...	75,000,000	21,294,223	$ 425,170,424.09	
Less: Common Stock Expense...			835,888.64	
Paid-In Capital...			83,581,499.00	
Other Comprehensive Income...			-	
Retained Earnings...			831,803,763.59	
Total Proprietary Capital..			1,339,719,798.04	54.79
Long-Term Debt				
Pollution Control Bonds..				
Jefferson County 2000 Series A due 05/01/27 5.375%................			25,000,000.00	
Trimble County 2000 Series A due 08/01/30 Var%.....................			83,335,000.00	
Jefferson County 2001 Series A due 09/01/26 Var%..................			22,500,000.00	
Trimble County 2001 Series A due 09/01/26 Var%.....................			27,500,000.00	
Jefferson County 2001 Series A due 09/01/27 Var%...................			10,104,000.00	
Jefferson County 2001 Series B due 11/01/27 Var%..................			35,000,000.00	
Trimble County 2001 Series A due 10/01/32 Var%.....................			41,665,000.00	
Trimble County 2001 Series B due 11/01/27 Var%.....................			35,000,000.00	
Louisville Metro 2003 Series A due 10/01/33 1.900%.................			128,000,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%.................			40,000,000.00	
Louisville Metro 2007 Series A due 06/01/33 5.625%.................			31,000,000.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%.................			35,200,000.00	
Trimble County 2007 Series A due 06/01/33 4.600%..................			60,000,000.00	
Total Pollution Control Bonds..			574,304,000.00	23.49
First Mortgage Bonds..				
First Mortgage Bond Due 11/15/15 1.625%..................................			250,000,000.00	
First Mortgage Bond Due 11/15/40 5.125%..................................			285,000,000.00	
Total First Mortgage Bonds..			535,000,000.00	21.88
Less: First Mortgage Bonds Debt Discount.....................................				
First Mortgage Bond Due 11/15/15 1.625%..................................			(786,895.85)	
First Mortgage Bond Due 11/15/40 5.125%..................................			(3,044,813.35)	
			(3,831,709.20)	-0.16
Total First Mortgage Bonds - Net of Debt Discount........................			531,168,290.80	21.72
Total Capitalization..			$ 2,445,192,088.84	100.00

June 21, 2011

Louisville Gas and Electric Company
Summary Trial Balance
May 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 4,792,382,669.03	$ 4,792,382,669.03
Reserves for Depreciation and Amortization		(2,086,932,887.81)
Depreciation of Plant		
Electric	(1,752,871,870.35)	
Gas	(233,740,096.47)	
Common	(82,419,046.77)	
Amortization of Plant		
Common	(17,900,974.22)	
Gas	(800.00)	
Electric	(100.00)	
Investments		22,280,480.00
Special Funds	21,674,314.80	
Ohio Valley Electric Corporation	594,286.00	
Nonutility Property	11,879.20	
Cash	42,642,184.10	42,642,184.10
Special Deposits		6,103,356.02
MAN Margin Call	5,407,342.13	
Other Special Deposits	696,013.89	
Temporary Cash Investments	16,607,994.23	16,607,994.23
Accounts Receivable - Less Reserve		117,302,831.48
Customers - Active	56,484,422.17	
Unbilled Revenues	51,863,377.20	
Wholesale Sales	4,160,561.47	
Bechtel Liquidated Damages	2,338,474.40	
IMPA	1,910,698.08	
IMEA	1,866,896.04	
Sundry Accounts Receivable	1,297,020.08	
Transmission Sales	445,392.51	
Damage Claims	398,080.45	
Officers and Employees	39.83	
IMEA/IMPA Net Portion of Bechtel Liquidated damages	(234,460.00)	
Other	218,127.22	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	2,159,564.10	
Reserve	(1,657,225.00)	
Accrual	(1,624,828.30)	
Bechtel Reserve	(1,400,634.40)	
Recoveries	(534,735.80)	
A/R Miscellaneous	(387,938.57)	
Accounts Receivable from Associated Companies		17,220,727.53
LG&E-KU Energy Services /Kentucky Utilities	17,220,727.53	
Fuel		64,042,394.78
Coal 1,394,907.72 Tons @ $45.63; MMBtu 31,805,127.96 @ 200.11¢	63,644,268.18	
Fuel Oil 138,621.95 Gallons @ 253.86¢	351,905.41	
Gas Pipeline 5,200 Mcf @ $8.89	46,221.19	
Plant Materials and Operating Supplies		29,638,442.60
Regular Materials and Supplies	29,246,202.93	
Limestone 45,171.89 Tons @ $8.68	392,239.67	
Stores Expense Undistributed	5,123,126.75	5,123,126.75
Gas Stored Underground - Current		12,379,663.46
Gas Stored Underground* 2,508,798 Mcf (14.73 psia) @ $4.93	12,379,663.46	
Emission Allowances	2,331.27	2,331.27

June 21, 2011

Louisville Gas and Electric Company
Summary Trial Balance
May 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Prepayments		$ 6,486,268.51
Insurance	5,172,064.75	
Rights of Way	240,000.04	
Franchises	210,329.13	
Taxes	161,096.94	
Risk Management and Workers Compensation	90,000.00	
Other	612,777.65	
Miscellaneous Current Assets		681,197.76
Derivative Asset - Non-Hedging	681,197.76	
Unamortized Debt Expense		13,330,061.12
Trimble County 2000 Series A due 08/01/30 Var%	741,891.31	
Jefferson County 2001 Series A due 09/01/26 Var%	151,337.52	
Trimble County 2001 Series A due 09/01/26 Var%	164,547.27	
Jefferson County 2001 Series A due 09/01/27 Var%	331,378.06	
Jefferson County 2001 Series B due 11/01/27 Var%	180,505.35	
Trimble County 2001 Series B due 11/01/27 Var%	180,534.96	
Trimble County 2002 Series A due 10/01/32 Var%	794,056.79	
Louisville Metro 2003 Series A Due 10/01/33 1.900%	437,947.58	
Trimble County 2007 Series A due 06/01/33 4.600%	1,045,757.06	
Louisville Metro 2007 Series B Due 06/01/33 1.900%	164,437.20	
First Mortgage Bond due 11/15/15 1.625%	2,142,055.37	
First Mortgage Bond due 11/15/40 5.125%	3,334,255.38	
Revolving Credit Agreement	3,661,357.27	
Unamortized Loss on Bonds	21,429,634.70	21,429,634.70
Accumulated Deferred Income Taxes		55,739,575.24
Federal		
Electric	36,254,027.82	
Gas	9,973,533.92	
State		
Electric	7,666,985.90	
Gas	1,845,027.60	
Regulatory Assets		358,597,038.27
Pension and Postretirement Benefits	213,180,670.00	
2009 Winter Storm	40,185,191.89	
Interest Rate Ineffectiveness	37,119,897.97	
2008 Wind Storm	21,578,638.39	
Deferred Taxes - FAS 109		
Federal		
Electric	12,716,651.23	
State		
Electric	2,319,146.12	
Swap Termination	9,087,999.40	
Asset Retirement Obligations		
Electric	7,626,909.39	
Gas	294,601.43	
Common	4,499.69	
Fuel Adjustment Clause	4,904,000.00	
Gas Supply Clause/PBR	4,479,551.41	
Enviromental Cost Recovery	1,262,409.00	
Rate Case Expenses	1,201,337.97	
MISO Exit Fee	1,197,036.10	
KCCS Funding	695,115.40	
EKPC FERC Transmission Costs	466,324.08	
CMRG Funding	211,380.00	
General Management Audit	65,678.80	
Other Deferred Debits	1,033,868.72	1,033,868.72
Total Assets	$ 3,496,090,957.76	$ 3,496,090,957.76

* Excludes:

	$	Mcf
Non-recoverable Base Gas	9,648,855.00	7,880,000
Recoverable Base Gas	2,139,990.00	2,930,000
	11,788,845.00	10,810,000

June 21, 2011

Louisville Gas and Electric Company
Summary Trial Balance
May 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 1,339,719,798.04
Common Stock	425,170,424.09	
Less: Common Stock Expense	835,888.64	
Paid-In Capital	83,581,499.00	
Retained Earnings	831,803,763.59	
Pollution Control Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,168,290.80	531,168,290.80
Accounts Payable		83,744,950.28
Regular	80,170,209.67	
Salaries and Wages Accrued	3,547,114.61	
Employee Withholdings Payable	27,626.00	
Accounts Payable to Associated Companies		13,185,424.92
LG&E - KU Energy Services/Kentucky Utilities	13,185,424.92	
Customers' Deposits	22,522,323.63	22,522,323.63
Taxes Accrued	10,625,328.89	10,625,328.89
Interest Accrued		6,438,420.39
Jefferson County 2000 Series A due 05/01/27 5.375%	111,979.17	
Trimble County 2000 Series A due 08/01/30 Var%	10,370.58	
Jefferson County 2001 Series A due 09/01/26 Var%	140,239.70	
Trimble County 2001 Series A due 09/01/26 Var%	17,479.44	
Jefferson County 2001 Series A due 09/01/27 Var%	359.25	
Jefferson County 2001 Series B due 11/01/27 Var%	13,549.32	
Trimble County 2001 Series A due 10/01/32 Var%	8,374.09	
Trimble County 2001 Series B due 11/01/27 Var%	13,089.04	
Louisville Metro 2003 Series A due 10/01/33 1.900%	412,088.99	
Louisville Metro 2005 Series A due 02/01/35 5.750%	760,277.78	
Louisville Metro 2007 Series A due 06/01/33 5.625%	871,875.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%	258,231.09	
Trimble County 2007 Series A due 06/01/33 4.600%	1,380,000.00	
Interest Rate Swaps	604,916.27	
First Mortgage Bond due 11/15/15 1.625%	180,555.56	
First Mortgage Bond due 11/15/40 5.125%	649,166.67	
Customers' Deposits	998,625.97	
Other	7,242.47	
Dividends Declared		25,000,000.00
Dividend Payable to LG&E and KU Energy LLC	25,000,000.00	
Miscellaneous Current and Accrued Liabilities		28,264,294.97
No-Notice Gas Payable	7,033,877.96	
Vacation Pay Accrued	6,664,885.16	
Customer Overpayments	5,453,047.92	
Derivative Liabilities - Non-Hedging	3,689,104.54	
SFAS 133 Derivative Liability	2,973,515.81	
Tax Collections Payable	1,123,201.36	
Postretirement Benefits - Current	624,694.04	
Unearned Revenue	65,316.70	
Other	636,651.48	

Louisville Gas and Electric Company
Summary Trial Balance
May 31, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Accumulated Deferred Income Taxes		$ 492,983,143.27
Federal		
Electric	356,460,724.49	
Gas	67,873,903.77	
State		
Electric	58,689,713.87	
Gas	9,958,801.14	
Investment Tax Credit		44,371,073.13
Advanced Coal Credit	23,509,948.00	
Job Development Credit		
Electric	20,225,983.98	
Gas	635,141.15	
Regulatory Liabilities		59,210,182.72
Deferred Taxes		
Federal		
Electric	28,076,175.45	
Gas	1,099,659.47	
State		
Electric	15,933,625.10	
Gas	2,396,149.22	
DSM Cost Recovery	5,144,862.62	
Gas Supply Clause/PBR	3,381,267.81	
Asset Retirement Obligations		
Gas	2,138,103.93	
Electric	249,953.00	
MISO Schedule 10 Charges	461,700.50	
Purchased Gas Adjustment - Texas Gas	328,685.62	
Customers' Advances for Construction		8,092,132.24
Line Extensions		
Gas	6,559,025.11	
Electric	772,546.22	
Customer Advances - Museum Plaza	696,013.89	
Other	64,547.02	
Asset Retirement Obligations		51,902,235.56
Electric	34,669,884.50	
Gas	17,127,663.31	
Common	104,687.75	
Other Deferred Credits	18,472,668.22	18,472,668.22
Miscellaneous Long-Term Liabilities		39,234,121.95
Long-Term Derivative Liabilities - SFAS 133	34,174,617.54	
Workers' Compensation	5,059,504.41	
Accumulated Provision for Benefits		146,852,568.75
Postretirement Benefits - SFAS 106	81,723,027.07	
Pension Payable	61,662,688.50	
Post Employment Benefits Payable	3,698,041.00	
Post Employment Medicare Subsidy	(231,187.82)	
Total Liabilities and Stockholders' Equity	$ 3,496,090,957.76	$ 3,496,090,957.76

June 21, 2011

Louisville Gas and Electric Company
Statement of Cash Flows
May 31, 2011

	Year to Date	
	2011	2010
Cash Flows from Operating Activities		
Net income	$ 46,060,511.63	$ 34,296,509.54
Items not requiring (providing) cash currently:		
Depreciation	59,081,544.98	54,126,693.55
Amortization	3,256,385.20	3,351,957.99
Deferred income taxes - net	17,594,732.15	4,690,800.80
Investment tax credit - net	(1,153,503.00)	(1,042,407.00)
Gain on disposal of assets	(62,480.08)	(1,050.00)
Other	(8,449,727.89)	17,103,137.23
Change in receivables	55,649,718.84	11,641,473.06
Change in inventory	51,085,912.19	30,581,644.53
Change in allowance inventory	397.69	347.89
Change in payables and accrued expenses	2,485,906.80	(43,503,744.26)
Change in regulatory assets	(14,560,675.10)	(160,750.36)
Change in regulatory liabilities	7,783,834.26	(30,169,322.43)
Change in other deferred debits	(10,322,805.24)	(1,045,582.43)
Change in other deferred credits	12,921,584.94	10,327,870.79
Other	(69,624,632.99)	(23,722,613.00)
Net cash provided (used) by operating activities	151,746,704.38	66,474,965.90
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(55,545,210.44)	(3,575,616.33)
Gross additions to common utility plant - construction expenditures	(1,667,639.01)	(3,410,627.01)
Proceeds received from sales of property	62,480.08	1,050.00
Change in restricted cash	(2,723,406.80)	-
Change in derivatives	(931,039.15)	(915,186.06)
Other	159,275,556.75	-
Net cash provided (used) by investing activities	98,470,741.43	(7,900,379.40)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(967,279.32)	(26,566.61)
Net change in short-term debt	(174,876,000.00)	(29,650,000.00)
Dividends on common stock	(17,250,000.00)	(30,000,000.00)
Net cash provided (used) by financing activities	(193,093,279.32)	(59,676,566.61)
Net Increase (Decrease) in Cash and Cash Equivalents	57,124,166.49	(1,101,980.11)
Cash and Cash Equivalents at Beginning of Period	2,126,011.84	5,195,486.38
Cash and Cash Equivalents at End of Period	$ 59,250,178.33	$ 4,093,506.27

June 21, 2011

Louisville Gas and Electric 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						
Jefferson County 2000 Series A due 05/01/27 5.375%.......................	$ 111,979.18	$ 111,979.16	$ 559,895.86	$ 559,895.83	$ 1,343,749.95	$ 1,343,750.02
Trimble County 2000 Series A due 08/01/30 Var%............................	12,037.29	38,310.94	108,925.75	160,199.96	340,006.75	346,870.33
Jefferson County 2001 Series A due 09/01/26 Var%.........................	1,392.11	5,444.93	11,439.84	19,684.56	38,890.41	37,973.00
Trimble County 2001 Series A due 09/01/26 Var%............................	9,342.46	14,691.78	47,955.48	72,946.57	140,023.98	220,768.50
Jefferson County 2001 Series A due 09/01/27 Var%.........................	23,886.99	13,376.70	116,352.72	59,517.12	245,743.15	175,900.69
Jefferson County 2001 Series B due 11/01/27 Var%.........................	33,214.53	37,176.70	150,090.16	118,491.74	388,103.55	326,621.87
Trimble County 2001 Series A due 10/01/32 Var%............................	9,545.28	20,824.51	65,476.81	167,526.79	192,916.91	241,402.85
Trimble County 2001 Series B due 11/01/27 Var%............................	32,938.35	38,260.26	147,239.43	119,575.30	384,213.35	327,705.41
Louisville Metro 2003 Series A due 10/01/33 1.900%.......................	202,666.67	-	939,022.21	-	939,022.21	27,045.30
Louisville Metro 2005 Series A due 02/01/35 5.750%.......................	191,666.67	191,666.66	958,333.32	958,333.33	2,299,999.90	2,300,000.02
Louisville Metro 2007 Series A due 06/01/33 5.625%.......................	145,312.49	145,312.50	726,562.45	726,562.50	1,743,749.90	1,743,750.00
Louisville Metro 2007 Series B due 06/01/33 1.900%........................	55,733.34	-	258,231.11	-	258,231.11	-
Trimble County 2007 Series A due 06/01/33 4.600%..........................	230,000.00	230,000.00	1,150,000.00	1,150,000.00	2,760,000.00	2,760,000.00
Interest Rate Swaps..	604,916.21	690,528.92	3,156,394.73	3,319,781.66	7,534,953.38	7,211,177.63
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/15/15 1.625%..	338,541.67	-	1,692,708.33	-	2,200,520.84	-
First Mortgage Bond due 11/15/40 5.125%..	1,217,187.50	-	6,085,937.50	-	7,911,718.75	-
Fidelia/PPL..	-	2,220,149.99	-	11,100,750.01	12,219,825.02	26,641,800.05
Revolving Credit Agreement..	-	-	185,005.01	-	779,683.35	-
Total..................................………………………………..........	3,220,360.74	3,757,723.05	16,359,570.71	18,533,265.37	41,721,352.51	43,704,765.67
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense...	175,850.30	15,518.34	870,477.64	77,591.70	1,246,260.95	186,216.76
Amortization of Loss on Reacquired Debt..	101,002.97	100,864.68	505,014.85	504,229.87	1,212,035.71	1,241,414.54
Total..	276,853.27	116,383.02	1,375,492.49	581,821.57	2,458,296.66	1,427,631.30
Other Interest Charges						
Customers' Deposits..	111,089.41	111,116.64	538,041.11	569,532.69	1,357,414.88	1,467,227.66
Other Tax Deficiencies...	-	-	-	-	(17,500.00)	(14,880.00)
Interest on DSM Cost Recovery..	1,752.41	708.19	4,564.53	17,299.81	13,679.96	109,944.27
Interest on Debt to Associated Companies..	-	24,735.68	8,862.00	108,547.99	162,735.89	337,970.87
Other Interest Expense...	42,608.59	41,478.14	184,554.54	224,504.09	902,820.62	766,344.05
Total..	155,450.41	178,038.65	736,022.18	919,884.58	2,419,151.35	2,666,606.85
Total Interest..	$ 3,652,664.42	$ 4,052,144.72	$ 18,471,085.38	$ 20,034,971.52	$ 46,598,800.52	$ 47,799,003.82

June 21, 2011

Louisville Gas and Electric 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	$ 1,450,538.00	$ 1,222,746.10	$ 7,249,698.00	$ 6,112,497.18
Unemployment	3,958.59	4,516.97	106,323.37	117,185.48
FICA	717,604.79	541,644.37	3,341,577.03	3,027,263.62
Public Service Commission Fee	161,096.90	161,675.42	805,484.50	808,377.10
Federal Income	88,889.98	2,343,232.70	7,828,909.28	16,845,310.84
State Income	1,087,945.48	427,337.27	4,557,331.49	2,931,304.53
Miscellaneous	(6,398.36)	-	23,555.88	20,133.86
Total Charged to Operating Expense	3,503,635.38	4,701,152.83	23,912,879.55	29,862,072.61
Taxes Charged to Other Accounts	556,117.31	(1,003,292.33)	1,068,709.99	(605,092.42)
Taxes Accrued on Intercompany Accounts	(298,632.90)	(233,912.40)	(1,411,398.76)	(1,249,761.50)
Total Taxes Charged	$ 3,761,119.79	$ 3,463,948.10	$ 23,570,190.78	$ 28,007,218.69

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	$ 11,354,131.66	$ 7,318,993.00	$ 11,508,650.09	$ 7,164,474.57
Unemployment	54,386.05	87,525.38	141,169.30	742.13
FICA	590,648.24	2,701,659.76	2,817,777.77	474,530.24
Federal Income	(3,741,320.05)	7,445,765.68	4,760,919.00	(1,056,473.37)
State Income	229,108.93	4,487,457.27	1,024,076.00	3,692,490.20
Kentucky Sales and Use Tax	1,088,857.95	1,450,030.70	2,199,473.03	339,415.62
Miscellaneous	22,339.97	78,758.99	90,949.46	10,149.50
Totals	$ 9,598,152.75	$ 23,570,190.78	$ 22,543,014.65	$ 10,625,328.89

June 21, 2011

Louisville Gas and Electric Company
Summary of Utility Plant
May 31, 2011

		Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101	**Utility Plant In Service**						
	Common						
	Common General Plant	$ 159,884,459.36	$ 4,733,838.14	$ (280,263.63)	$ -	$ 4,453,574.51	$ 164,338,033.87
	Common Intangible Plant	56,455,326.72	6,691,632.97	(1,661,801.58)	-	5,029,831.39	61,485,158.11
		216,339,786.08	11,425,471.11	(1,942,065.21)	-	9,483,405.90	225,823,191.98
	Electric						
	Electric Distribution	927,289,038.50	18,447,378.50	(4,130,322.91)	47,153.43	14,364,209.02	941,653,247.52
	Electric General Plant	16,521,615.59	247,788.85	(1,934,885.80)	-	(1,687,096.95)	14,834,518.64
	Electric Hydro Production	41,680,209.14	410,641.30	(55,573.58)	-	355,067.72	42,035,276.86
	Electric Intangible Plant	2,340.29	-	-	-	-	2,340.29
	Electric Other Production	229,401,033.01	22,818.51	(3,857.24)	38,429.14	57,390.41	229,458,423.42
	Electric Steam Production	1,930,347,044.43	19,782,200.87	(5,494,798.53)	4,144,130.56	18,431,532.90	1,948,778,577.33
	Electric Transmission	247,742,496.14	1,352,011.90	(521,503.11)	(47,153.43)	783,355.36	248,525,851.50
		3,392,983,777.10	40,262,839.93	(12,140,941.17)	4,182,559.70	32,304,458.46	3,425,288,235.56
	Gas						
	Gas Distribution	549,799,120.70	29,436,019.85	(378,399.88)	97,729.20	29,155,349.17	578,954,469.87
	Gas General Plant	9,178,093.57	351,040.76	(995,401.23)	(97,729.20)	(742,089.67)	8,436,003.90
	Gas Intangible Plant	1,187.49	-	-	-	-	1,187.49
	Gas Storage	78,415,311.06	996,579.44	(588,414.06)	-	408,165.38	78,823,476.44
	Gas Transmission	16,661,869.68	142,121.04	(531.82)	-	141,589.22	16,803,458.90
		654,055,582.50	30,925,761.09	(1,962,746.99)	-	28,963,014.10	683,018,596.60
	Total 101 Accounts	4,263,379,145.68	82,614,072.13	(16,045,753.37)	4,182,559.70	70,750,878.46	4,334,130,024.14
105	**Plant Held For Future Use**						
	Electric						
	Electric Distribution	649,014.48	-	-	-	-	649,014.48
	Electric Steam Production	4,182,559.70	-	-	(4,182,559.70)	(4,182,559.70)	-
		4,831,574.18	-	-	(4,182,559.70)	(4,182,559.70)	649,014.48
	Total 105001	$ 4,831,574.18	$ -	$ -	$ (4,182,559.70)	$ (4,182,559.70)	$ 649,014.48

June 21, 2011

Louisville Gas and Electric Company
Summary of Utility Plant
May 31, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
106 **Completed Construction Not Classified**						
Common						
Common General Plant	$ 597,158.63	$ 3,785,512.71	$ -	$ -	$ 3,785,512.71	$ 4,382,671.34
Common Intangible Plant	2,714,931.36	(1,139,891.52)	-	-	(1,139,891.52)	1,575,039.84
	3,312,089.99	2,645,621.19	-	-	2,645,621.19	5,957,711.18
Electric						
Electric Distribution	11,544,733.90	6,454,336.38	-	-	6,454,336.38	17,999,070.28
Electric General Plant	50,763.87	203,596.76	-	-	203,596.76	254,360.63
Electric Hydro Production	16,952.26	371,941.51	-	-	371,941.51	388,893.77
Electric Intangible Plant	-	-	-	-	-	-
Electric Other Production	1,767,208.21	1,558,330.60	-	-	1,558,330.60	3,325,538.81
Electric Steam Production	15,929,229.77	180,339,093.26	-	-	180,339,093.26	196,268,323.03
Electric Transmission	35,045,472.82	4,531,375.38	-	-	4,531,375.38	39,576,848.20
	64,354,360.83	193,458,673.89	-	-	193,458,673.89	257,813,034.72
Gas						
Gas Distribution	24,420,156.16	(10,670,578.39)	-	-	(10,670,578.39)	13,749,577.77
Gas General Plant	126,992.17	(21,033.58)	-	-	(21,033.58)	105,958.59
Gas Intangible Plant	-	-	-	-	-	-
Gas Storage	951,426.06	786,491.66	-	-	786,491.66	1,737,917.72
Gas Transmission	-	919,767.29	-	-	919,767.29	919,767.29
	25,498,574.39	(8,985,353.02)	-	-	(8,985,353.02)	16,513,221.37
Total 106 Accounts	93,165,025.21	187,118,942.06	-	-	187,118,942.06	280,283,967.27
117 **Gas Stored Underground-Noncurrent**						
Gas						
Gas Stored Nonrecoverable	2,139,990.00	-	-	-	-	2,139,990.00
	2,139,990.00	-	-	-	-	2,139,990.00
Total 117001	2,139,990.00	-	-	-	-	2,139,990.00
121 **Nonutility Property**						
Common						
Non Utility Property	75,239.56	-	-	-	-	75,239.56
	75,239.56	-	-	-	-	75,239.56
Total 121001	75,239.56	-	-	-	-	75,239.56
107 **Construction Work In Progress**						
Common	21,243,879.89	(12,403,453.29)	-	-	(12,403,453.29)	8,840,426.60
Electric	324,323,732.14	(191,367,038.81)	-	-	(191,367,038.81)	132,956,693.33
Gas	39,756,306.91	(6,373,753.70)	-	-	(6,373,753.70)	33,382,553.21
	385,323,918.94	(210,144,245.80)	-	-	(210,144,245.80)	175,179,673.14
Total Plant (Non-CWIP)	4,363,590,974.63	269,733,014.19	(16,045,753.37)	$ -	253,687,260.82	4,617,278,235.45
Total Plant + CWIP	4,748,914,893.57	59,588,768.39	(16,045,753.37)	$ -	43,543,015.02	4,792,457,908.59
Total Plant + CWIP - Non Utility	$ 4,748,839,654.01	$ 59,588,768.39	$ (16,045,753.37)	$ -	$ 43,543,015.02	$ 4,792,382,669.03

June 21, 2011

Louisville Gas and Electric 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										
Common General Plant	$ (77,263,235.10)	$ (5,217,227.58)	$ 280,263.63	$ -	$ -	$ -	$ -	$ -	$ -	$ (82,200,199.05)
Common General Plant - ARO	(343.19)	(858.50)	-	-	-	-	-	-	-	(1,201.69)
Electric Distribution	(277,000,365.75)	(7,180,216.08)	4,130,322.91	(382.60)	-	-	-	-	-	(280,050,641.52)
Electric Distribution - ARO	(1,256.54)	(2,514.11)	-	-	-	-	-	-	-	(3,770.65)
Electric General Plant	(12,910,034.19)	(144,896.82)	1,934,885.80	(19,392.53)	-	-	-	-	-	(11,139,437.74)
Electric Hydro Production	(9,718,276.66)	(231,999.32)	55,573.58	-	-	-	-	-	-	(9,894,702.40)
Electric Hydro Production - ARO	(364.10)	(728.55)	-	-	-	-	-	-	-	(1,092.65)
Electric Other Production	(60,282,055.17)	(3,405,425.34)	3,857.24	-	-	-	-	-	-	(63,683,623.27)
Electric Other Production - ARO	(192.68)	(434.22)	-	-	-	-	-	-	-	(626.90)
Electric Steam Production	(1,029,518,070.37)	(23,525,267.07)	4,846,109.87	-	-	-	-	-	-	(1,048,197,227.57)
Electric Steam Production - ARO	(204,061.94)	(1,147,315.07)	648,688.66	-	-	-	-	-	-	(702,688.35)
Electric Transmission	(119,192,606.75)	(1,817,586.36)	521,503.11	382.60	-	-	-	-	-	(120,488,307.40)
Electric Transmission - ARO	(41.40)	(82.85)	-	-	-	-	-	-	-	(124.25)
Gas Distribution	(125,049,477.23)	(4,754,671.21)	303,360.61	(13,332.40)	-	-	-	-	-	(129,514,120.23)
Gas Distribution - ARO	(49,734.93)	(198,467.84)	75,039.27	-	-	-	-	-	-	(173,163.50)
Gas General Plant	(6,299,629.20)	(121,690.44)	995,401.23	32,724.93	-	-	-	-	-	(5,393,193.48)
Gas Storage	(31,288,281.49)	(449,361.60)	193,008.60	-	-	-	-	-	-	(31,544,634.49)
Gas Storage - ARO	(39,466.10)	(485,051.45)	395,405.46	-	-	-	-	-	-	(129,112.09)
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(9,448,605.32)	(23,010.08)	531.82	-	-	-	-	-	-	(9,471,083.58)
Non Utility Property	(63,360.36)	-	-	-	-	-	-	-	-	(63,360.36)
	(1,758,329,458.47)	(48,706,804.49)	14,383,951.79	-	-	-	-	-	-	(1,792,652,311.17)
Cost Of Removal										
Common General Plant	(688,372.47)	(115,009.11)	-	-	-	-	68,506.21	-	-	(734,875.37)
Electric Distribution	(146,715,298.78)	(2,842,350.94)	-	(55.48)	-	-	2,333,693.05	-	-	(147,224,012.15)
Electric General Plant	3,866.64	-	-	-	-	-	-	-	-	3,866.64
Electric Hydro Production	736,907.70	(17,639.18)	-	-	-	-	34,591.42	-	-	753,859.94
Electric Other Production	(2,505,175.99)	(146,240.99)	-	-	-	-	33,120.15	-	-	(2,618,296.83)
Electric Steam Production	(94,783,295.15)	(7,016,276.72)	-	-	-	-	1,979,201.25	-	-	(99,820,370.62)
Electric Transmission	(24,538,454.78)	(585,282.96)	-	55.48	-	-	(70,121.47)	-	-	(25,193,803.73)
Gas Distribution	(60,212,131.14)	(1,340,273.03)	-	-	-	-	1,239,469.39	-	-	(60,312,934.78)
Gas General Plant	(0.02)	-	-	-	-	-	-	-	-	(0.02)
Gas Storage	(170,437.90)	(58,111.13)	-	-	-	-	549,226.94	-	-	320,677.91
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	(3,016,813.95)	(5,690.46)	-	-	-	-	32,210.90	-	-	(2,990,293.51)
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	$ (331,889,205.84)	$ (12,126,874.52)	$ -	$ -	$ -	$ -	$ 6,199,897.84	$ -	$ -	$ (337,816,182.52)

June 21, 2011

Louisville Gas and Electric 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
Salvage										
Common General Plant	$ 278,074.55	$ 159.70	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 278,234.25
Electric Distribution	17,535,024.98	575,309.46	-	-	-	-	-	(182,166.06)	-	17,928,168.38
Electric General Plant	138,281.25	962.75	-	-	-	-	-	-	-	139,244.00
Electric Hydro Production	376,638.17	-	-	-	-	-	-	-	-	376,638.17
Electric Other Production	(18,998.67)	-	-	-	-	-	-	-	-	(18,998.67)
Electric Steam Production	22,028,570.14	838,645.59	-	-	-	-	-	(11,318.62)	-	22,855,897.11
Electric Transmission	6,247,368.67	108,407.87	-	-	-	-	-	-	-	6,355,776.54
Gas Distribution	3,594,440.75	82,023.60	-	-	-	-	-	-	-	3,676,464.35
Gas General Plant	225,788.37	880.58	-	-	-	-	-	-	-	226,668.95
Gas Storage	269,933.04	7,105.65	-	-	-	-	-	-	-	277,038.69
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	217,923.11	2,133.92	-	-	-	-	-	-	-	220,057.03
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	50,893,044.36	1,615,629.12	-	-	-	-	-	(193,484.68)	-	52,315,188.80
Total Reserves										
Common	(77,737,236.57)	(5,332,935.49)	280,263.63	-	-	-	68,506.21	-	-	(82,721,402.22)
Electric	(1,730,321,891.37)	(46,540,930.91)	12,140,941.17	(19,392.53)	-	-	4,310,484.40	(193,484.68)	-	(1,760,624,273.92)
Gas	(231,266,492.01)	(7,344,183.49)	1,962,746.99	19,392.53	-	-	1,820,907.23	-	-	(234,807,628.75)
	(2,039,325,619.95)	(59,218,049.89)	14,383,951.79	-	-	-	6,199,897.84	(193,484.68)	-	(2,078,153,304.89)
Retirement Work In Progress										
Common	342,947.00	-	-	-	-	(68,506.21)	(17,551.70)	(17,894.00)	-	238,995.09
Electric	9,603,653.21	-	-	97,518.30	(803,385.38)	(3,881,859.58)	2,954,160.61	(173,264.94)	(44,418.65)	7,752,403.57
Gas	2,523,160.64	-	-	(38,225.44)	(1,053,809.06)	(1,025,103.51)	667,216.82	(3,332.90)	(2,374.27)	1,067,532.28
	12,469,760.85	-	-	59,292.86	(1,857,194.44)	(4,975,469.30)	3,603,825.73	(194,491.84)	(46,792.92)	9,058,930.94
YTD ACTIVITY	(2,026,855,859.10)	(59,218,049.89)	14,383,951.79	59,292.86	(1,857,194.44)	(4,975,469.30)	9,803,723.57	(387,976.52)	(46,792.92)	(2,069,094,373.95)
Amortization										
Common	(16,306,390.60)	(3,256,385.20)	1,661,801.58	-	-	-	-	-	-	(17,900,974.22)
Electric	(100.00)	-	-	-	-	-	-	-	-	(100.00)
Gas	(800.00)	-	-	-	-	-	-	-	-	(800.00)
AMORTIZATION TOTAL	(16,307,290.60)	(3,256,385.20)	1,661,801.58	-	-	-	-	-	-	(17,901,874.22)
Depreciation & Amortization Total	$ (2,043,163,149.70)	$ (62,474,435.09)	$ 16,045,753.37	$ 59,292.86	$ (1,857,194.44)	$ (4,975,469.30)	$ 9,803,723.57	$ (387,976.52)	$ (46,792.92)	$ (2,086,996,248.17)
Depr & Amort - Nonutility for Balance Sheet										(2,086,932,887.81)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)	$ 2,705,739,864.67									$ 2,705,449,781.22

June 21, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
May 31, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues...	$ 82,342,454.95	$ -	$ 82,342,454.95
Gas Operating Revenues...	15,822,650.10	-	15,822,650.10
Total Operating Revenues..	98,165,105.05	-	98,165,105.05
Fuel for Electric Generation..	27,927,729.83	-	27,927,729.83
Power Purchased..	6,396,864.92	-	6,396,864.92
Gas Supply Expenses...	7,748,745.56	-	7,748,745.56
Other Operation Expenses...	20,079,042.25	-	20,079,042.25
Maintenance..	9,772,439.82	-	9,772,439.82
Depreciation..	12,745,145.63	6.13	12,745,151.76
Amortization Expense...	669,166.96	-	669,166.96
Regulatory Credits...	(1,366,601.03)	-	(1,366,601.03)
Taxes			
Federal Income..	88,889.98	-	88,889.98
State Income..	1,087,945.48	-	1,087,945.48
Deferred Federal Income - Net...................................	3,431,528.62	8,228.79	3,439,757.41
Deferred State Income - Net.......................................	(608,867.93)	1,500.69	(607,367.24)
Property and Other..	2,326,799.92	-	2,326,799.92
Investment Tax Credit..	-	-	-
Amortization of Investment Tax Credit......................	(236,034.00)	-	(236,034.00)
Loss (Gain) from Disposition of Allowances................	-	-	-
Accretion Expense...	220,800.15	-	220,800.15
Total Operating Expenses...	90,283,596.16	9,735.61	90,293,331.77
Net Operating Income..	7,881,508.89	(9,735.61)	7,871,773.28
Other Income Less Deductions...................................	252,722.76	-	252,722.76
Income Before Interest Charges.................................	8,134,231.65	(9,735.61)	8,124,496.04
Interest on Long-Term Debt..	3,220,360.74	(25,017.63)	3,195,343.11
Amortization of Debt Expense - Net.............................	276,853.27	-	276,853.27
Other Interest Expenses..	155,450.41	-	155,450.41
Total Interest Charges...	3,652,664.42	(25,017.63)	3,627,646.79
Net Income...	$ 4,481,567.23	$ 15,282.02	$ 4,496,849.25

Note: Purchase accounting is subject to change through October 31, 2011

June 21, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
May 31, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues	$ 412,517,431.57	$ -	$ 412,517,431.57
Gas Operating Revenues	171,907,885.65	-	171,907,885.65
Total Operating Revenues	584,425,317.22	-	584,425,317.22
Fuel for Electric Generation	142,799,303.79	-	142,799,303.79
Power Purchased	30,938,890.68	-	30,938,890.68
Gas Supply Expenses	100,042,135.22	-	100,042,135.22
Other Operation Expenses	96,533,699.79	27,884.66	96,561,584.45
Maintenance	48,601,523.71	-	48,601,523.71
Depreciation	59,081,544.98	0.02	59,081,545.00
Amortization Expense	3,256,385.20	-	3,256,385.20
Regulatory Credits	(2,936,556.98)	-	(2,936,556.98)
Taxes			
Federal Income	7,828,909.28	-	7,828,909.28
State Income	4,557,331.49	-	4,557,331.49
Deferred Federal Income - Net	17,090,013.95	31,979.94	17,121,993.89
Deferred State Income - Net	(266,940.57)	5,832.21	(261,108.36)
Property and Other	11,526,638.78	-	11,526,638.78
Investment Tax Credit	-	-	-
Amortization of Investment Tax Credit	(1,153,503.00)	-	(1,153,503.00)
Loss (Gain) from Disposition of Allowances	(2,577.94)	-	(2,577.94)
Accretion Expense	1,101,104.39	-	1,101,104.39
Total Operating Expenses	518,997,902.77	65,696.83	519,063,599.60
Net Operating Income	65,427,414.45	(65,696.83)	65,361,717.62
Other Income Less Deductions	(895,817.44)	-	(895,817.44)
Income Before Interest Charges	64,531,597.01	(65,696.83)	64,465,900.18
Interest on Long-Term Debt	16,359,570.71	(125,088.15)	16,234,482.56
Amortization of Debt Expense - Net	1,375,492.49	-	1,375,492.49
Other Interest Expenses	736,022.18	-	736,022.18
Total Interest Charges	18,471,085.38	(125,088.15)	18,345,997.23
Net Income	$ 46,060,511.63	$ 59,391.32	$ 46,119,902.95

Note: Purchase accounting is subject to change through October 31, 2011

June 21, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
May 31, 2011

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……………………………	$ 852,322,196.36	$ 757,127,061.99	$ (808,855,173.14)	$ -	$ 43,467,023.22	$ 757,127,061.99
Add:						
Net Income (Loss) for Period…………………………	4,481,567.23	2,448,313.79	15,282.02	-	4,496,849.25	2,448,313.79
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	25,000,000.00	-	-	-	25,000,000.00	-
Balance at End of Period…………………………………	$ 831,803,763.59	$ 759,575,375.78	$ (808,839,891.12)	$ -	$ 22,963,872.47	$ 759,575,375.78

Note: Purchase accounting is subject to change through October 31, 2011

June 21, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
May 31, 2011

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……………………………	$ 827,993,251.96	$ 755,278,866.24	$ (808,899,282.44)	$ -	$ 19,093,969.52	$ 755,278,866.24
Add:						
Net Income (Loss) for Period…………………………	46,060,511.63	34,296,509.54	59,391.32	-	46,119,902.95	34,296,509.54
Deduct:						
Adjustment to Retained Earnings……………………	-	-		-	-	-
Common Dividends						
Common Stock Without Par Value………………	42,250,000.00	30,000,000.00	-	-	42,250,000.00	30,000,000.00
Balance at End of Period…………………………………	$ 831,803,763.59	$ 759,575,375.78	$ (808,839,891.12)	$ -	$ 22,963,872.47	$ 759,575,375.78

Note: Purchase accounting is subject to change through October 31, 2011

June 21, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
May 31, 2011

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……	$ 759,575,375.78	$ 715,121,788.28	$ -	$ -	$ 759,575,375.78	$ 715,121,788.28
Add:						
Net Income (Loss) for Period……	139,478,387.81	119,453,587.50	107,000.40	-	139,585,388.21	119,453,587.50
Deduct:						
Adjustment to Retained Earnings……	-	-	808,946,891.52	-	808,946,891.52	-
Common Dividends						
Common Stock Without Par Value……	67,250,000.00	75,000,000.00	-	-	67,250,000.00	75,000,000.00
Balance at End of Period……	$ 831,803,763.59	$ 759,575,375.78	$ (808,839,891.12)	$ -	$ 22,963,872.47	$ 759,575,375.78

Note: Purchase accounting is subject to change through October 31, 2011

June 21, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of May 31, 2011

Assets	Without Purchase Accounting	Purchase Accounting	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 4,792,382,669.03	$ (0.02)	$ 4,792,382,669.01
Less: Reserves for Depreciation and Amortization....	2,086,932,887.81	-	2,086,932,887.81
Total..	2,705,449,781.22	(0.02)	2,705,449,781.20
Investments			
Ohio Valley Electric Corporation.............................	594,286.00	-	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	-	11,879.20
Special Funds...	21,674,314.80	-	21,674,314.80
Total..	22,280,480.00	-	22,280,480.00
Current and Accrued Assets			
Cash..	42,642,184.10	-	42,642,184.10
Special Deposits...	6,103,356.02	-	6,103,356.02
Temporary Cash Investments...................................	16,607,994.23	-	16,607,994.23
Accounts Receivable - Less Reserve.........................	117,302,831.48	-	117,302,831.48
Accounts Receivable from Associated Companies....	17,220,727.53	-	17,220,727.53
Materials and Supplies - At Average Cost................			
Fuel..	64,042,394.78	-	64,042,394.78
Plant Materials and Operating Supplies.................	29,638,442.60	-	29,638,442.60
Stores Expense...	5,123,126.75	-	5,123,126.75
Gas Stored Underground.......................................	12,379,663.46	-	12,379,663.46
Emission Allowances...	2,331.27	-	2,331.27
Prepayments..	6,486,268.51	-	6,486,268.51
Miscellaneous Current and Accrued Assets..............	681,197.76	-	681,197.76
Total..	318,230,518.49	-	318,230,518.49
Deferred Debits and Other			
Unamortized Debt Expense......................................	13,330,061.12	(3,590,008.32)	9,740,052.80
Unamortized Loss on Bonds....................................	21,429,634.70	-	21,429,634.70
Accumulated Deferred Income Taxes.......................	55,739,575.24	83,151,053.04	138,890,628.28
Deferred Regulatory Assets.....................................	358,597,038.27	11,717,641.10	370,314,679.37
Other Deferred Debits..	1,033,868.72	190,013,665.22	191,047,533.94
Goodwill...	-	389,157,351.59	389,157,351.59
Total..	450,130,178.05	670,449,702.63	1,120,579,880.68
Total Assets..	$ 3,496,090,957.76	$ 670,449,702.61	$ 4,166,540,660.37

Note: Purchase accounting is subject to change through October 31, 2011

June 21, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of May 31, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting	Total
Proprietary Capital			
Common Stock	$ 425,170,424.09	$ -	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	-	835,888.64
Paid-In Capital	83,581,499.00	1,194,085,869.02	1,277,667,368.02
Other Comprehensive Income	-	-	-
Retained Earnings	831,803,763.59	(808,839,891.12)	22,963,872.47
Total Proprietary Capital	1,339,719,798.04	385,245,977.90	1,724,965,775.94
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	6,401,593.59	580,705,593.59
First Mortgage Bonds	531,168,290.80	-	531,168,290.80
LT Notes Payable to Associated Companies	-	-	-
Total Long-Term Debt	1,105,472,290.80	6,401,593.59	1,111,873,884.39
Total Capitalization	2,445,192,088.84	391,647,571.49	2,836,839,660.33
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies	-	-	-
Accounts Payable	83,744,950.28	-	83,744,950.28
Accounts Payable to Associated Companies	13,185,424.92	-	13,185,424.92
Customer Deposits	22,522,323.63	-	22,522,323.63
Taxes Accrued	10,625,328.89	-	10,625,328.89
Dividends Declared	25,000,000.00	-	25,000,000.00
Interest Accrued	6,438,420.39	-	6,438,420.39
Miscellaneous Current and Accrued Liabilities	28,264,294.97	-	28,264,294.97
Total	189,780,743.08	-	189,780,743.08
Deferred Credits and Other			
Accumulated Deferred Income Taxes	492,983,143.27	80,660,833.12	573,643,976.39
Investment Tax Credit	44,371,073.13	-	44,371,073.13
Regulatory Liabilities	59,210,182.72	190,013,665.22	249,223,847.94
Customer Advances for Construction	8,092,132.24	-	8,092,132.24
Asset Retirement Obligations	51,902,235.56	-	51,902,235.56
Other Deferred Credits	18,472,668.22	8,127,632.78	26,600,301.00
Miscellaneous Long-Term Liabilities	39,234,121.95	-	39,234,121.95
Misc Long-Term Liab Due to Assoc Cos	-	-	-
Accum Provision for Postretirement Benefits	146,852,568.75	-	146,852,568.75
Total	861,118,125.84	278,802,131.12	1,139,920,256.96
Total Liabilities and Stockholders' Equity	$ 3,496,090,957.76	$ 670,449,702.61	$ 4,166,540,660.37

Note: Purchase accounting is subject to change through October 31, 2011

June 21, 2011

LOUISVILLE GAS AND ELECTRIC COMPANY

Financial Reports

April 30, 2011

Index
Financial and Operating Reports

Louisville Gas and Electric 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.

Louisville Gas and Electric Company
Comparative Statement of Income
April 30, 2011

	Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 73,908,472.30	$ 69,696,210.01	$ 4,212,262.29	6.04
Gas Operating Revenues...	18,642,881.93	13,495,328.29	5,147,553.64	38.14
Total Operating Revenues...	92,551,354.23	83,191,538.30	9,359,815.93	11.25
Fuel for Electric Generation...	26,601,752.01	27,565,248.99	(963,496.98)	(3.50)
Power Purchased..	4,930,724.70	3,613,611.17	1,317,113.53	36.45
Gas Supply Expenses..	8,665,043.42	5,061,333.84	3,603,709.58	71.20
Other Operation Expenses..	17,724,384.01	17,783,707.78	(59,323.77)	(0.33)
Maintenance..	11,168,994.71	10,337,593.60	831,401.11	8.04
Depreciation..	11,806,358.00	10,847,126.18	959,231.82	8.84
Amortization Expense...	657,834.15	608,531.20	49,302.95	8.10
Regulatory Credits..	(467,346.27)	(181,685.10)	(285,661.17)	(157.23)
Taxes				
Federal Income..	1,727,882.62	1,404,772.59	323,110.03	23.00
State Income...	315,115.37	256,189.52	58,925.85	23.00
Deferred Federal Income - Net.................................	-	(958,044.71)	958,044.71	100.00
Deferred State Income - Net......................................	-	(174,719.40)	174,719.40	100.00
Property and Other..	2,272,396.13	1,973,711.81	298,684.32	15.13
Investment Tax Credit...	-	-	-	-
Amortization of Investment Tax Credit.....................	(236,034.00)	(208,481.00)	(27,553.00)	(13.22)
Loss (Gain) from Disposition of Allowances...............	-	-	-	-
Accretion Expense..	221,493.64	167,045.35	54,448.29	32.59
Total Operating Expenses...	85,388,598.49	78,095,941.82	7,292,656.67	9.34
Net Operating Income..	7,162,755.74	5,095,596.48	2,067,159.26	40.57
Other Income Less Deductions.................................	(961,726.27)	(1,639,854.76)	678,128.49	41.35
Income Before Interest Charges................................	6,201,029.47	3,455,741.72	2,745,287.75	79.44
Interest on Long-Term Debt...	3,322,584.57	3,747,395.83	(424,811.26)	(11.34)
Amortization of Debt Expense - Net............................	275,309.85	116,383.02	158,926.83	136.56
Other Interest Expenses..	119,638.44	193,468.17	(73,829.73)	(38.16)
Total Interest Charges...	3,717,532.86	4,057,247.02	(339,714.16)	(8.37)
Net Income..	$ 2,483,496.61	$ (601,505.30)	$ 3,085,001.91	512.88

May 26, 2011

Louisville Gas and Electric Company
Comparative Statement of Income
April 30, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 330,174,976.62	$ 299,991,555.44	$ 30,183,421.18	10.06
Gas Operating Revenues..	156,085,235.55	149,200,459.86	6,884,775.69	4.61
Total Operating Revenues...	486,260,212.17	449,192,015.30	37,068,196.87	8.25
Fuel for Electric Generation...	114,871,573.96	110,707,297.44	4,164,276.52	3.76
Power Purchased...	24,542,025.76	20,100,272.07	4,441,753.69	22.10
Gas Supply Expenses..	92,293,389.66	88,059,327.25	4,234,062.41	4.81
Other Operation Expenses..	76,454,657.54	72,610,110.01	3,844,547.53	5.29
Maintenance..	38,829,083.89	36,326,370.91	2,502,712.98	6.89
Depreciation..	46,336,399.35	43,227,626.11	3,108,773.24	7.19
Amortization Expense...	2,587,218.24	2,740,862.65	(153,644.41)	(5.61)
Regulatory Credits...	(1,569,955.95)	(721,768.32)	(848,187.63)	(117.52)
Taxes				
Federal Income..	7,740,019.30	14,502,078.14	(6,762,058.84)	(46.63)
State Income...	3,469,386.01	2,503,967.26	965,418.75	38.56
Deferred Federal Income - Net.................................	13,658,485.33	1,920,879.99	11,737,605.34	611.05
Deferred State Income - Net......................................	341,927.36	400,912.77	(58,985.41)	(14.71)
Property and Other..	9,199,838.86	8,154,874.38	1,044,964.48	12.81
Investment Tax Credit...	-	-	-	-
Amortization of Investment Tax Credit.....................	(917,469.00)	(833,926.00)	(83,543.00)	(10.02)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	880,304.24	663,209.30	217,094.94	32.73
Total Operating Expenses...	428,714,306.61	400,327,633.82	28,386,672.79	7.09
Net Operating Income..	57,545,905.56	48,864,381.48	8,681,524.08	17.77
Other Income Less Deductions.................................	(1,148,540.20)	(1,033,358.93)	(115,181.27)	(11.15)
Income Before Interest Charges................................	56,397,365.36	47,831,022.55	8,566,342.81	17.91
Interest on Long-Term Debt...	13,139,209.97	14,775,542.32	(1,636,332.35)	(11.07)
Amortization of Debt Expense - Net............................	1,098,639.22	465,438.55	633,200.67	136.04
Other Interest Expenses..	580,571.77	741,845.93	(161,274.16)	(21.74)
Total Interest Charges...	14,818,420.96	15,982,826.80	(1,164,405.84)	(7.29)
Net Income..	$ 41,578,944.40	$ 31,848,195.75	$ 9,730,748.65	30.55

May 26, 2011

Louisville Gas and Electric 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..	$ 1,045,794,988.15	$ 919,320,092.52	$ 126,474,895.63	13.76
Gas Operating Revenues...	309,832,131.57	286,216,229.20	23,615,902.37	8.25
Total Operating Revenues...	1,355,627,119.72	1,205,536,321.72	150,090,798.00	12.45
Fuel for Electric Generation...	372,720,602.86	321,445,856.62	51,274,746.24	15.95
Power Purchased...	58,821,472.38	55,430,103.58	3,391,368.80	6.12
Gas Supply Expenses..	173,237,670.46	164,433,052.35	8,804,618.11	5.35
Other Operation Expenses..	230,657,552.10	216,146,486.61	14,511,065.49	6.71
Maintenance...	114,203,818.06	63,299,842.14	50,903,975.92	80.42
Depreciation...	134,318,776.51	129,661,021.33	4,657,755.18	3.59
Amortization Expense...	7,573,344.49	8,607,032.81	(1,033,688.32)	(12.01)
Regulatory Credits..	(5,117,919.08)	(2,165,646.56)	(2,952,272.52)	(136.32)
Taxes				
Federal Income..	22,112,548.34	43,285,674.46	(21,173,126.12)	(48.91)
State Income...	7,012,586.18	6,806,064.74	206,521.44	3.03
Deferred Federal Income - Net.................................	39,404,610.34	8,709,868.00	30,694,742.34	352.41
Deferred State Income - Net......................................	2,311,039.03	2,151,974.66	159,064.37	7.39
Property and Other...	23,616,588.30	22,643,657.68	972,930.62	4.30
Investment Tax Credit...	-	2,737,009.49	(2,737,009.49)	(100.00)
Amortization of Investment Tax Credit.....................	(2,585,317.00)	(2,917,274.28)	331,957.28	11.38
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense..	3,501,200.57	1,977,653.24	1,523,547.33	77.04
Total Operating Expenses...	1,181,785,995.60	1,042,217,916.73	139,568,078.87	13.39
Net Operating Income..	173,841,124.12	163,318,404.99	10,522,719.13	6.44
Other Income Less Deductions.................................	10,602,291.07	3,151,136.65	7,451,154.42	236.46
Income Before Interest Charges................................	184,443,415.19	166,469,541.64	17,973,873.55	10.80
Interest on Long-Term Debt...	42,258,714.82	43,587,189.08	(1,328,474.26)	(3.05)
Amortization of Debt Expense - Net............................	2,297,826.41	1,435,480.97	862,345.44	60.07
Other Interest Expenses..	2,441,739.59	2,573,676.86	(131,937.27)	(5.13)
Total Interest Charges...	46,998,280.82	47,596,346.91	(598,066.09)	(1.26)
Net Income..	$ 137,445,134.37	$ 118,873,194.73	$ 18,571,939.64	15.62

May 26, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings
April 30, 2011

	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period..	$ 849,838,699.75	$ 757,728,567.29	$ 827,993,251.96	$ 755,278,866.24	$ 757,127,061.99	$ 713,253,867.26
Add:						
Net Income for Period..	2,483,496.61	(601,505.30)	41,578,944.40	31,848,195.75	137,445,134.37	118,873,194.73
Deduct:						
Common Dividends						
Common Stock Without Par Value.....................	-	-	17,250,000.00	30,000,000.00	42,250,000.00	75,000,000.00
Balance at End of Period...	$ 852,322,196.36	$ 757,127,061.99	$ 852,322,196.36	$ 757,127,061.99	$ 852,322,196.36	$ 757,127,061.99

May 26, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of April 30, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,782,878,078.55	$ 4,564,494,960.09
Less Reserves for Depreciation and Amortization	2,077,990,172.73	1,991,374,248.54
Total	2,704,887,905.82	2,573,120,711.55
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	20,392,613.99	14,729,449.18
Total	20,998,779.19	15,335,614.38
Current and Accrued Assets		
Cash	32,004,651.77	5,847,850.51
Special Deposits	5,336,432.10	755,355.97
Temporary Cash Investments	32,004,573.78	119.71
Accounts Receivable - Less Reserve	116,387,007.31	118,456,375.85
Accounts Receivable from Associated Companies	11,414,595.15	12,314,747.96
Materials and Supplies - At Average Cost		
Fuel	64,634,046.64	73,203,744.22
Plant Materials and Operating Supplies	29,834,678.95	29,387,046.33
Stores Expense	5,079,805.34	4,653,117.81
Gas Stored Underground	14,392,608.85	14,842,906.51
Emission Allowances	2,409.88	3,916.15
Prepayments	7,049,940.71	6,542,096.80
Miscellaneous Current and Accrued Assets	724,075.07	5,801,250.84
Total	318,864,825.55	271,808,528.66
Deferred Debits and Other		
Unamortized Debt Expense	13,309,465.49	3,792,088.35
Unamortized Loss on Bonds	21,530,637.65	22,742,534.79
Accumulated Deferred Income Taxes	53,426,611.12	51,895,455.16
Deferred Regulatory Assets	361,306,009.06	320,567,422.64
Other Deferred Debits	1,251,973.01	2,095,968.23
Total	450,824,696.33	401,093,469.17
Total Assets	$ 3,495,576,206.89	$ 3,261,358,323.76

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	(11,094,243.55)
Retained Earnings	852,322,196.36	757,127,061.99
Total Proprietary Capital	1,360,238,230.81	1,253,948,852.89
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds	531,144,969.14	-
LT Notes Payable to Associated Companies	-	485,000,000.00
Total Long-Term Debt	1,105,448,969.14	896,104,000.00
Total Capitalization	2,465,687,199.95	2,150,052,852.89
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	133,491,400.00
Accounts Payable	72,770,225.00	68,051,345.04
Accounts Payable to Associated Companies	27,020,672.69	30,812,887.97
Customer Deposits	23,394,006.56	23,941,242.89
Taxes Accrued	7,782,784.18	13,407,762.97
Interest Accrued	13,874,035.61	4,315,904.54
Miscellaneous Current and Accrued Liabilities	29,874,305.15	34,238,967.29
Total	174,716,029.19	308,259,510.70
Deferred Credits and Other		
Accumulated Deferred Income Taxes	487,780,888.27	425,917,166.76
Investment Tax Credit	44,607,107.13	47,192,424.13
Regulatory Liabilities	61,508,554.02	56,089,200.04
Customer Advances for Construction	8,115,146.29	9,395,487.39
Asset Retirement Obligations	53,172,083.34	33,706,838.44
Other Deferred Credits	15,198,179.97	15,483,167.15
Miscellaneous Long-Term Liabilities	36,567,706.97	36,593,225.16
Accum Provision for Postretirement Benefits	148,223,311.76	178,668,451.10
Total	855,172,977.75	803,045,960.17
Total Liabilities and Stockholders' Equity	$ 3,495,576,206.89	$ 3,261,358,323.76

May 26, 2011

Louisville Gas and Electric 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	75,000,000	21,294,223	$ 425,170,424.09	
Less: Common Stock Expense			835,888.64	
Paid-In Capital			83,581,499.00	
Other Comprehensive Income			-	
Retained Earnings			852,322,196.36	
Total Proprietary Capital			1,360,238,230.81	55.17
Long-Term Debt				
Pollution Control Bonds				
Jefferson County 2000 Series A due 05/01/27 5.375%			25,000,000.00	
Trimble County 2000 Series A due 08/01/30 Var%			83,335,000.00	
Jefferson County 2001 Series A due 09/01/26 Var%			22,500,000.00	
Trimble County 2001 Series A due 09/01/26 Var%			27,500,000.00	
Jefferson County 2001 Series A due 09/01/27 Var%			10,104,000.00	
Jefferson County 2001 Series B due 11/01/27 Var%			35,000,000.00	
Trimble County 2001 Series B due 11/01/27 Var%			35,000,000.00	
Trimble County 2002 Series A due 10/01/32 Var%			41,665,000.00	
Louisville Metro 2003 Series A due 10/01/33 1.900%			128,000,000.00	
Louisville Metro 2005 Series A due 02/01/35 5.750%			40,000,000.00	
Louisville Metro 2007 Series A due 06/01/33 5.625%			31,000,000.00	
Louisville Metro 2007 Series B due 06/01/33 1.900%			35,200,000.00	
Trimble County 2007 Series A due 06/01/33 4.600%			60,000,000.00	
Total Pollution Control Bonds			574,304,000.00	23.29
First Mortgage Bonds				
First Mortgage Bond Due 11/15/15 1.625%			250,000,000.00	
First Mortgage Bond Due 11/15/40 5.125%			285,000,000.00	
Total First Mortgage Bonds			535,000,000.00	21.70
Less: First Mortgage Bonds Debt Discount				
First Mortgage Bond Due 11/15/15 1.625%			(801,604.18)	
First Mortgage Bond Due 11/15/40 5.125%			(3,053,426.68)	
			(3,855,030.86)	-0.16
Total First Mortgage Bonds - Net of Debt Discount			531,144,969.14	21.54
Total Capitalization			$ 2,465,687,199.95	100.00

May 26, 2011

Louisville Gas and Electric Company
Summary Trial Balance
April 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Utility Plant		
At Original Cost	$ 4,782,878,078.55	$ 4,782,878,078.55
Reserves for Depreciation and Amortization		(2,077,990,172.73)
Depreciation of Plant		
Electric	(1,746,215,668.26)	
Gas	(232,352,708.30)	
Common	(81,354,027.66)	
Amortization of Plant		
Common	(18,066,868.51)	
Gas	(800.00)	
Electric	(100.00)	
Investments		20,998,779.19
Special Funds	20,392,613.99	
Ohio Valley Electric Corporation	594,286.00	
Nonutility Property	11,879.20	
Cash	32,004,651.77	32,004,651.77
Special Deposits		5,336,432.10
MAN Margin Call	4,640,670.93	
Other Special Deposits	695,761.17	
Temporary Cash Investments	32,004,573.78	32,004,573.78
Accounts Receivable - Less Reserve		116,387,007.31
Customers - Active	65,393,177.07	
Unbilled Revenues	43,830,487.92	
Bechtel Liquidated Damages	2,332,584.40	
Insurance Claims	2,029,443.27	
IMEA	1,934,271.58	
IMPA	1,812,894.28	
Wholesale Sales	1,104,647.48	
Sundry Accounts Receivable	950,610.50	
Damage Claims	393,063.22	
Transmission Sales	351,141.34	
Electricity Swaps	76,784.71	
Officers and Employees	39.83	
IMEA/IMPA Net Portion of Bechtel Liquidated damages	(232,987.48)	
Other	195,840.16	
Reserves for Uncollectible Accounts		
Utility Customers		
Charged Off	1,715,302.69	
Reserve	(1,996,418.00)	
Bechtel Reserve	(1,400,634.40)	
Accrual	(1,258,028.71)	
Recoveries	(457,273.98)	
A/R Miscellaneous	(387,938.57)	
Accounts Receivable from Associated Companies		11,414,595.15
LG&E-KU Energy Services /Kentucky Utilities	11,414,595.15	
Fuel		64,634,046.64
Coal 1,418,917.23 Tons @ $45.15; MMBtu 32,334,980.73 @ 198.13¢	64,065,900.37	
Fuel Oil 195,650.24 Gallons @ 268.61¢	525,541.15	
Gas Pipeline 5,200.00 Mcf @ $8.19	42,605.12	
Plant Materials and Operating Supplies		29,834,678.95
Regular Materials and Supplies	29,328,490.94	
Limestone 58,596.47 Tons @ $8.64	506,188.01	
Stores Expense Undistributed	5,079,805.34	5,079,805.34
Gas Stored Underground - Current		14,392,608.85
Gas Stored Underground* 2,916,731.00 Mcf (14.73 psia) @ $4.93	14,392,608.85	
Emission Allowances	2,409.88	2,409.88

May 26, 2011

Louisville Gas and Electric Company
Summary Trial Balance
April 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Prepayments		$ 7,049,940.71
Insurance	5,223,189.16	
Taxes	322,193.84	
Franchises	257,921.85	
Rights of Way	240,000.04	
Risk Management and Workers Compensation	90,000.00	
Other	916,635.82	
Miscellaneous Current Assets		724,075.07
Derivative Asset - Non-Hedging	724,075.07	
Unamortized Debt Expense		13,309,465.49
Trimble County 2000 Series A due 08/01/30 Var%	745,116.92	
Jefferson County 2001 Series A due 09/01/26 Var%	152,164.50	
Trimble County 2001 Series A due 09/01/26 Var%	165,446.44	
Jefferson County 2001 Series A due 09/01/27 Var%	333,077.44	
Jefferson County 2001 Series B due 11/01/27 Var%	181,421.62	
Trimble County 2001 Series B due 11/01/27 Var%	181,451.38	
Trimble County 2002 Series A due 10/01/32 Var%	797,158.57	
Louisville Metro 2003 Series A 11/20/03 Due 10/01/33 1.900%	423,843.02	
Trimble County 2007 Series A due 06/01/33 4.600%	149,321.34	
Louisville Metro 2007 Series B 04/26/07 Due 06/01/33 1.900%	1,049,718.26	
First Mortgage Bond due 11/15/15 1.625%	2,115,360.14	
First Mortgage Bond due 11/15/40 5.125%	3,268,880.73	
Revolving Credit Agreement	3,746,505.13	
Unamortized Loss on Bonds	21,530,637.65	21,530,637.65
Accumulated Deferred Income Taxes		53,426,611.12
Federal		
Electric	34,901,504.65	
Gas	9,369,848.36	
State		
Electric	7,420,325.14	
Gas	1,734,932.97	
Regulatory Assets		361,306,009.06
Pension and Postretirement Benefits	213,180,670.00	
2009 Winter Storm	40,550,511.81	
Interest Rate Ineffectiveness	34,277,580.41	
2008 Wind Storm	21,774,807.83	
Deferred Taxes - FAS 109		
Federal		
Electric	12,716,651.23	
State		
Electric	2,319,146.12	
Swap Termination	9,109,539.06	
Asset Retirement Obligations		
Electric	7,487,880.88	
Gas	558,326.17	
Common	3,850.36	
Enviromental Cost Recovery	5,766,408.00	
Gas Supply Clause/PBR	5,364,927.56	
Fuel Adjustment Clause	4,324,000.00	
Rate Case Expenses	1,265,564.90	
MISO Exit Fee	1,259,522.30	
KCCS Funding	713,407.91	
EKPC FERC Transmission Costs	480,455.12	
CMRG Funding	121,950.00	
General Management Audit	30,809.40	
Other Deferred Debits	1,251,973.01	1,251,973.01
Total Assets	$ 3,495,576,206.89	$ 3,495,576,206.89

* Excludes:

	$	Mcf
Non-recoverable Base Gas	9,648,855.00	7,880,000
Recoverable Base Gas	2,139,990.00	2,930,000
	11,788,845.00	10,810,000

May 26, 2011

Louisville Gas and Electric Company
Summary Trial Balance
April 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Proprietary Capital		$ 1,360,238,230.81
Common Stock	425,170,424.09	
Less: Common Stock Expense	835,888.64	
Paid-In Capital	83,581,499.00	
Retained Earnings	852,322,196.36	
Pollution Control Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,144,969.14	531,144,969.14
Accounts Payable		72,770,225.00
Regular	69,374,194.26	
Salaries and Wages Accrued	3,361,837.25	
Employee Withholdings Payable	34,193.49	
Accounts Payable to Associated Companies		27,020,672.69
LG&E-KU Energy Services /Kentucky Utilities	27,020,672.69	
Customers' Deposits	23,394,006.56	23,394,006.56
Taxes Accrued	7,782,784.18	7,782,784.18
Interest Accrued		13,874,035.61
Jefferson County 2000 Series A due 05/01/27 5.375%	671,875.00	
Trimble County 2000 Series A due 08/01/30 Var%	17,778.13	
Jefferson County 2001 Series A due 09/01/26 Var%	116,352.72	
Trimble County 2001 Series A due 09/01/26 Var%	8,136.98	
Jefferson County 2001 Series A due 09/01/27 Var%	224.53	
Jefferson County 2001 Series B due 11/01/27 Var%	13,235.89	
Trimble County 2001 Series B due 11/01/27 Var%	12,130.14	
Trimble County 2002 Series A due 10/01/32 Var%	12,492.65	
Louisville Metro 2003 Series A due 10/01/33 1.900%	209,422.32	
Louisville Metro 2005 Series A due 02/01/35 5.750%	568,611.11	
Louisville Metro 2007 Series A due 06/01/33 5.625%	726,562.50	
Louisville Metro 2007 Series B due 06/01/33 1.900%	202,497.76	
Trimble County 2007 Series A due 06/01/33 4.600%	1,150,000.00	
Interest Rate Swaps	687,322.71	
First Mortgage Bond due 11/15/15 1.625%	1,861,979.17	
First Mortgage Bond due 11/15/40 5.125%	6,694,531.25	
Customers' Deposits	915,392.69	
Other	5,490.06	
Miscellaneous Current and Accrued Liabilities		29,874,305.15
No-Notice Gas Payable	9,562,798.51	
Vacation Pay Accrued	6,664,885.16	
Customer Overpayments	5,210,349.64	
Derivative Liabilities - Non-Hedging	3,309,326.57	
SFAS 133 Derivative Liability	2,769,377.85	
Tax Collections Payable	978,680.84	
Postretirement Benefits - Current	624,694.04	
Home Energy Assistance	275,582.61	
Unearned Revenue	133,010.95	
Other	345,598.98	

Louisville Gas and Electric Company
Summary Trial Balance
April 30, 2011

Account - Subsidiary Account	Balance Subsidiary Account	Balance as Shown on Balance Sheets
Accumulated Deferred Income Taxes		$ 487,780,888.27
Federal		
Electric	362,845,446.18	
Gas	56,040,418.16	
State		
Electric	60,140,935.66	
Gas	8,754,088.27	
Investment Tax Credit		44,607,107.13
Advanced Coal Credit	23,563,293.00	
Job Development Credit		
Electric	20,397,395.98	
Gas	646,418.15	
Regulatory Liabilities		61,508,554.02
Deferred Taxes		
Federal		
Electric	28,248,289.30	
Gas	974,161.01	
State		
Electric	15,944,611.08	
Gas	2,388,138.68	
DSM Cost Recovery	6,204,137.71	
Gas Supply Clause/PBR	3,763,178.91	
Asset Retirement Obligations		
Gas	2,394,399.45	
Electric	812,012.91	
MISO Schedule 10 Charges	438,120.94	
Purchased Gas Adjustment - Texas Gas	341,504.03	
Customers' Advances for Construction		8,115,146.29
Line Extensions		
Gas	6,587,166.46	
Electric	767,671.64	
Customer Advances - Museum Plaza	695,761.17	
Other	64,547.02	
Asset Retirement Obligations		53,172,083.34
Electric	35,250,813.59	
Gas	17,817,059.63	
Common	104,210.12	
Other Deferred Credits	15,198,179.97	15,198,179.97
Miscellaneous Long-Term Liabilities		36,567,706.97
Long-Term Derivative Liabilities - SFAS 133	31,508,202.56	
Workers' Compensation	5,059,504.41	
Accumulated Provision for Benefits		148,223,311.76
Postretirement Benefits - SFAS 106	83,093,770.08	
Pension Payable	61,662,688.50	
Post Employment Benefits Payable	3,698,041.00	
Post Employment Medicare Subsidy	(231,187.82)	
Total Liabilities and Stockholders' Equity	$ 3,495,576,206.89	$ 3,495,576,206.89

May 26, 2011

Louisville Gas and Electric Company
Statement of Cash Flows
April 30, 2011

	Year to Date 2011	Year to Date 2010
Cash Flows from Operating Activities		
Net income	$ 41,578,944.40	$ 31,848,195.75
Items not requiring (providing) cash currently:		
Depreciation	46,336,399.35	43,227,626.11
Amortization	2,587,218.24	2,740,862.65
Deferred income taxes - net	14,705,441.27	2,321,792.76
Investment tax credit - net	(917,469.00)	(833,926.00)
Gain on disposal of assets	(2,450.82)	-
Other	(6,997,374.24)	11,737,208.82
Change in receivables	63,204,869.27	16,924,268.00
Change in inventory	48,328,400.00	27,823,704.93
Change in allowance inventory	319.08	254.85
Change in payables and accrued expenses	(9,182,545.01)	(23,455,156.35)
Change in regulatory assets	(8,693,852.90)	(577,327.93)
Change in regulatory liabilities	10,082,205.56	(28,818,008.54)
Change in other deferred debits	(8,420,205.86)	(930,673.56)
Change in other deferred credits	9,647,096.69	7,501,835.70
Other	(66,711,683.45)	(26,180,486.37)
Net cash provided (used) by operating activities	135,545,312.58	63,330,170.82
Cash Flows from Investing Activities		
Gross additions to utility plant - construction expenditures	(38,262,709.86)	7,918,629.51
Gross additions to common utility plant - construction expenditures	(1,083,301.69)	(2,394,007.74)
Change in restricted cash	(1,497,707.79)	(754.03)
Change in derivatives	80,562.84	(1,267,038.13)
Proceeds received from sales of property	2,450.82	1,050.00
Other	160,018,761.82	-
Net cash provided (used) by investing activities	119,258,056.14	4,257,879.61
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	(794,155.01)	(26,566.59)
Net change in short-term debt	(174,876,000.00)	(36,909,000.00)
Dividends on common stock	(17,250,000.00)	(30,000,000.00)
Net cash provided (used) by financing activities	(192,920,155.01)	(66,935,566.59)
Net Increase (Decrease) in Cash and Cash Equivalents	61,883,213.71	652,483.84
Cash and Cash Equivalents at Beginning of Period	2,126,011.84	5,195,486.38
Cash and Cash Equivalents at End of Period	$ 64,009,225.55	$ 5,847,970.22

May 26, 2011

Louisville Gas and Electric 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						
Jefferson County 2000 Series A due 05/01/27 5.375%.......................	$ 111,979.14	$ 111,979.16	$ 447,916.68	$ 447,916.67	$ 1,343,749.93	$ 1,343,750.03
Trimble County 2000 Series A due 08/01/30 Var%............................	16,666.98	29,745.97	96,888.46	121,889.02	366,280.40	327,217.18
Jefferson County 2001 Series A due 09/01/26 Var%..........................	1,633.34	3,452.21	10,047.73	14,239.63	42,943.23	36,390.04
Trimble County 2001 Series A due 09/01/26 Var%............................	9,041.09	13,501.37	38,613.02	58,254.79	145,373.30	229,432.88
Jefferson County 2001 Series A due 09/01/27 Var%..........................	23,116.41	11,539.74	92,465.73	46,140.42	235,232.86	181,633.58
Jefferson County 2001 Series B due 11/01/27 Var%..........................	39,311.26	18,698.62	116,875.63	81,315.04	392,065.72	313,225.99
Trimble County 2001 Series B due 11/01/27 Var%............................	38,451.78	18,698.62	114,301.08	81,315.04	389,535.26	313,225.97
Trimble County 2002 Series A due 10/01/32 Var%............................	11,711.85	19,793.73	55,931.53	146,702.28	204,196.14	236,573.13
Louisville Metro 2003 Series A due 10/01/33 1.900%.......................	204,424.94	-	736,355.54	-	736,355.54	21,636.24
Louisville Metro 2005 Series A due 02/01/35 5.750%.......................	191,666.64	191,666.66	766,666.65	766,666.67	2,299,999.89	2,300,000.03
Louisville Metro 2007 Series A due 06/01/33 5.625%.......................	145,312.49	145,312.50	581,249.96	581,250.00	1,743,749.91	1,743,750.00
Louisville Metro 2007 Series B due 06/01/33 1.900%.......................	56,216.83	-	202,497.77	-	202,497.77	-
Trimble County 2007 Series A due 06/01/33 4.600%.........................	230,000.00	230,000.00	920,000.00	920,000.00	2,760,000.00	2,760,000.00
Interest Rate Swaps...	687,322.67	732,857.24	2,551,478.52	2,629,252.74	7,620,566.09	7,138,553.96
Loan Agreement - First Mortgage Bonds						
First Mortgage Bond due 11/15/2015 1.625%....................................	338,541.65	-	1,354,166.66	-	1,861,979.17	-
First Mortgage Bond due 11/15/2040 5.125%....................................	1,217,187.50	-	4,868,750.00	-	6,694,531.25	-
Fidelia/PPL..	-	2,220,150.01	-	8,880,600.02	14,439,975.01	26,641,800.05
Revolving Credit Agreement...	-	-	185,005.01	-	779,683.35	-
Total...................................……………………………...........	3,322,584.57	3,747,395.83	13,139,209.97	14,775,542.32	42,258,714.82	43,587,189.08
Amortization of Debt Expense - Net						
Amortization of Debt/Discount Expense...	174,306.88	15,518.34	694,627.34	62,073.36	1,085,928.99	186,216.07
Amortization of Loss on Reacquired Debt..	101,002.97	100,864.68	404,011.88	403,365.19	1,211,897.42	1,249,264.90
Total...	275,309.85	116,383.02	1,098,639.22	465,438.55	2,297,826.41	1,435,480.97
Other Interest Charges						
Customers' Deposits..	106,189.26	116,987.62	426,951.70	458,416.05	1,357,442.11	1,457,736.48
Other Tax Deficiencies...	-	-	-	-	(17,500.00)	(14,880.00)
Interest on DSM Cost Recovery..	1,629.58	951.96	2,812.12	16,591.62	12,635.74	115,831.20
Interest on Debt to Associated Companies..	-	19,943.47	8,862.00	83,812.31	187,471.57	357,044.10
Other Interest Expense...	11,819.60	55,585.12	141,945.95	183,025.95	901,690.17	657,945.08
Total...	119,638.44	193,468.17	580,571.77	741,845.93	2,441,739.59	2,573,676.86
Total Interest..	$ 3,717,532.86	$ 4,057,247.02	$ 14,818,420.96	$ 15,982,826.80	$ 46,998,280.82	$ 47,596,346.91

May 26, 2011

Louisville Gas and Electric Company
Analysis of Taxes Charged and Accrued
April 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	$ 1,449,790.00	$ 1,222,746.10	$ 5,799,160.00	$ 4,889,751.08
Unemployment	3,737.32	3,518.55	102,364.78	112,668.51
FICA	643,927.14	578,549.07	2,623,972.24	2,485,619.25
Public Service Commission Fee	161,096.90	161,675.42	644,387.60	646,701.68
Federal Income	1,727,882.62	1,404,772.59	7,740,019.30	14,502,078.14
State Income	315,115.37	256,189.52	3,469,386.01	2,503,967.26
Miscellaneous	13,844.77	7,222.67	29,954.24	20,133.86
Total Charged to Operating Expense	4,315,394.12	3,634,673.92	20,409,244.17	25,160,919.78
Taxes Charged to Other Accounts	(306,733.66)	(766,041.95)	512,592.68	398,199.91
Taxes Accrued on Intercompany Accounts	(247,472.59)	(232,985.17)	(1,112,765.85)	(1,015,849.10)
Total Taxes Charged	$ 3,761,187.87	$ 2,635,646.80	$ 19,809,071.00	$ 24,543,270.59

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	$ 11,354,131.66	$ 5,854,596.00	$ 11,401,818.50	$ 5,806,909.16
Unemployment	54,386.05	87,428.63	141,169.30	645.38
FICA	590,648.24	2,114,799.02	2,331,467.53	373,979.73
Federal Income	(3,741,320.05)	7,199,899.02	4,760,919.00	(1,302,340.03)
State Income	229,108.93	3,370,883.81	1,024,076.00	2,575,916.74
Kentucky Sales and Use Tax	1,088,857.95	1,110,615.08	1,880,239.61	319,233.42
Miscellaneous	22,339.97	70,849.45	84,749.64	8,439.78
Totals	$ 9,598,152.75	$ 19,809,071.00	$ 21,624,439.58	$ 7,782,784.18

May 26, 2011

Louisville Gas and Electric Company
Summary of Utility Plant
April 30, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
101 **Utility Plant In Service**						
Common						
Common General Plant..	$ 159,884,459.36	$ 2,154,042.02	$ (251,177.24)	$ -	$ 1,902,864.78	$ 161,787,324.14
Common Intangible Plant......................................	56,455,326.72	3,237,995.61	(826,740.33)	-	2,411,255.28	58,866,582.00
	216,339,786.08	5,392,037.63	(1,077,917.57)	-	4,314,120.06	220,653,906.14
Electric						
Electric Distribution...	927,289,038.50	16,070,338.66	(3,756,166.51)	47,153.43	12,361,325.58	939,650,364.08
Electric General Plant..	16,521,615.59	174,165.90	(1,889,481.22)	-	(1,715,315.32)	14,806,300.27
Electric Hydro Production.....................................	41,680,209.14	402,649.51	(55,573.58)	-	347,075.93	42,027,285.07
Electric Intangible Plant...	2,340.29	-	-	-	-	2,340.29
Electric Other Production......................................	229,401,033.01	22,818.51	(3,857.24)	38,429.14	57,390.41	229,458,423.42
Electric Steam Production......................................	1,930,347,044.43	7,647,739.06	(2,101,007.66)	4,144,130.56	9,690,861.96	1,940,037,906.39
Electric Transmission...	247,742,496.14	1,067,231.56	(320,547.50)	(47,153.43)	699,530.63	248,442,026.77
	3,392,983,777.10	25,384,943.20	(8,126,633.71)	4,182,559.70	21,440,869.19	3,414,424,646.29
Gas						
Gas Distribution...	549,799,120.70	28,767,863.87	(364,666.30)	97,729.20	28,500,926.77	578,300,047.47
Gas General Plant..	9,178,093.57	230,680.47	(905,104.36)	(97,729.20)	(772,153.09)	8,405,940.48
Gas Intangible Plant...	1,187.49	-	-	-	-	1,187.49
Gas Storage..	78,415,311.06	849,189.39	(193,039.61)	-	656,149.78	79,071,460.84
Gas Transmission...	16,661,869.68	142,121.04	(531.82)	-	141,589.22	16,803,458.90
	654,055,582.50	29,989,854.77	(1,463,342.09)	-	28,526,512.68	682,582,095.18
Total 101 Accounts...................................	4,263,379,145.68	60,766,835.60	(10,667,893.37)	4,182,559.70	54,281,501.93	4,317,660,647.61
105 **Plant Held For Future Use**						
Electric						
Electric Distribution...	649,014.48	-	-	-	-	649,014.48
Electric Steam Production......................................	4,182,559.70	-	-	(4,182,559.70)	(4,182,559.70)	-
	4,831,574.18	-	-	(4,182,559.70)	(4,182,559.70)	649,014.48
Total 105001..	$ 4,831,574.18	$ -	$ -	$ (4,182,559.70)	$ (4,182,559.70)	$ 649,014.48

Louisville Gas and Electric Company
Summary of Utility Plant
April 30, 2011

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
106 **Completed Construction Not Classified**						
Common						
Common General Plant..	$ 597,158.63	$ 3,722,716.18	$ -	$ -	$ 3,722,716.18	$ 4,319,874.81
Common Intangible Plant......................................	2,714,931.36	(572,795.80)	-	-	(572,795.80)	2,142,135.56
	3,312,089.99	3,149,920.38	-	-	3,149,920.38	6,462,010.37
Electric						
Electric Distribution...	11,544,733.90	5,389,709.95	-	-	5,389,709.95	16,934,443.85
Electric General Plant..	50,763.87	69,778.27	-	-	69,778.27	120,542.14
Electric Hydro Production.....................................	16,952.26	(8,960.47)	-	-	(8,960.47)	7,991.79
Electric Intangible Plant...	-	-	-	-	-	-
Electric Other Production......................................	1,767,208.21	1,558,330.60	-	-	1,558,330.60	3,325,538.81
Electric Steam Production......................................	15,929,229.77	186,016,780.55	-	-	186,016,780.55	201,946,010.32
Electric Transmission...	35,045,472.82	3,556,358.38	-	-	3,556,358.38	38,601,831.20
	64,354,360.83	196,581,997.28	-	-	196,581,997.28	260,936,358.11
Gas						
Gas Distribution...	24,420,156.16	(12,242,614.85)	-	-	(12,242,614.85)	12,177,541.31
Gas General Plant..	126,992.17	(15,888.54)	-	-	(15,888.54)	111,103.63
Gas Intangible Plant...	-	-	-	-	-	-
Gas Storage..	951,426.06	380,257.05	-	-	380,257.05	1,331,683.11
Gas Transmission...	-	927,034.14	-	-	927,034.14	927,034.14
	25,498,574.39	(10,951,212.20)	-	-	(10,951,212.20)	14,547,362.19
Total 106 Accounts....................................	93,165,025.21	188,780,705.46	-	-	188,780,705.46	281,945,730.67
						4,599,606,378.28
117 **Gas Stored Underground-Noncurrent**						
Gas						
Gas Stored Nonrecoverable...................................	2,139,990.00	-	-	-	-	2,139,990.00
	2,139,990.00	-	-	-	-	2,139,990.00
Total 117001..	2,139,990.00	-	-	-	-	2,139,990.00
121 **Nonutility Property**						
Common						
Non Utility Property...	75,239.56	-	-	-	-	75,239.56
	75,239.56	-	-	-	-	75,239.56
Total 121001..	75,239.56	-	-	-	-	75,239.56
107 **Construction Work In Progress**						
Common..	21,243,879.89	(7,458,656.32)	-	-	(7,458,656.32)	13,785,223.57
Electric..	324,323,732.14	(190,356,594.94)	-	-	(190,356,594.94)	133,967,137.20
Gas..	39,756,306.91	(7,025,971.89)	-	-	(7,025,971.89)	32,730,335.02
	385,323,918.94	(204,841,223.15)	-	-	(204,841,223.15)	180,482,695.79
Total Plant (Non-CWIP).......................................	4,363,590,974.63	249,547,541.06	(10,667,893.37)	-	238,879,647.69	4,602,470,622.32
Total Plant + CWIP...	4,748,914,893.57	44,706,317.91	(10,667,893.37)	-	34,038,424.54	4,782,953,318.11
Total Plant + CWIP - Non Utiltity............................	$ 4,748,839,654.01	$ 44,706,317.91	$ (10,667,893.37)	$ -	$ 34,038,424.54	$ 4,782,878,078.55

May 26, 2011

Louisville Gas and Electric 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										
Common General Plant...	$ (77,263,235.10)	$ (4,146,214.92)	$ 251,177.24	$ -	$ -	$ -	$ -	$ -	$ -	$ (81,158,272.78)
Common General Plant - ARO..	(343.19)	(686.80)	-	-	-	-	-	-	-	(1,029.99)
Electric Distribution...	(277,000,365.75)	(5,731,542.54)	3,756,166.51	(382.60)	-	-	-	-	-	(278,976,124.38)
Electric Distribution - ARO...	(1,256.54)	(2,011.29)	-	-	-	-	-	-	-	(3,267.83)
Electric General Plant..	(12,910,034.19)	(113,730.71)	1,889,481.22	-	-	-	-	-	-	(11,134,283.68)
Electric Hydro Production...	(9,718,276.66)	(185,167.90)	55,573.58	-	-	-	-	-	-	(9,847,870.98)
Electric Hydro Production - ARO..	(364.10)	(582.84)	-	-	-	-	-	-	-	(946.94)
Electric Other Production..	(60,282,055.17)	(2,721,888.29)	3,857.24	-	-	-	-	-	-	(63,000,086.22)
Electric Other Production - ARO...	(192.68)	(337.66)	-	-	-	-	-	-	-	(530.34)
Electric Steam Production...	(1,029,518,070.37)	(18,761,701.33)	2,082,190.82	-	-	-	-	-	-	(1,046,197,580.88)
Electric Steam Production - ARO..	(204,061.94)	(428,119.13)	18,816.84	-	-	-	-	-	-	(613,364.23)
Electric Transmission..	(119,192,606.75)	(1,451,283.33)	320,547.50	382.60	-	-	-	-	-	(120,322,959.98)
Electric Transmission - ARO...	(41.40)	(66.28)	-	-	-	-	-	-	-	(107.68)
Gas Distribution...	(125,049,477.23)	(3,791,270.47)	289,627.03	(13,332.40)	-	-	-	-	-	(128,564,453.07)
Gas Distribution - ARO...	(49,734.93)	(173,735.35)	75,039.27	-	-	-	-	-	-	(148,431.01)
Gas General Plant..	(6,299,629.20)	(94,737.11)	905,104.36	13,332.40	-	-	-	-	-	(5,475,929.55)
Gas Storage...	(31,288,281.49)	(358,554.69)	187,926.26	-	-	-	-	-	-	(31,458,909.92)
Gas Storage - ARO..	(39,466.10)	(84,112.36)	5,113.35	-	-	-	-	-	-	(118,465.11)
Gas Stored Nonrecoverable...	-	-	-	-	-	-	-	-	-	-
Gas Transmission..	(9,448,605.32)	(18,292.11)	531.82	-	-	-	-	-	-	(9,466,365.61)
Non Utility Property...	(63,360.36)	-	-	-	-	-	-	-	-	(63,360.36)
	(1,758,329,458.47)	(38,064,035.11)	9,841,153.04	-	-	-	-	-	-	(1,786,552,340.54)
Cost Of Removal										
Common General Plant...	(688,372.47)	(91,355.50)	-	-	-	-	68,506.21	-	-	(711,221.76)
Electric Distribution...	(146,715,298.78)	(2,268,171.94)	-	(55.48)	-	-	1,996,420.58	-	-	(146,987,105.62)
Electric General Plant..	3,866.64	-	-	-	-	-	-	-	-	3,866.64
Electric Hydro Production...	736,907.70	(14,080.77)	-	-	-	-	34,591.42	-	-	757,418.35
Electric Other Production..	(2,505,175.99)	(116,884.54)	-	-	-	-	33,120.15	-	-	(2,588,940.38)
Electric Steam Production...	(94,783,295.15)	(5,588,850.61)	-	-	-	-	893,389.33	-	-	(99,478,756.43)
Electric Transmission..	(24,538,454.78)	(467,499.59)	-	55.48	-	-	(96,075.77)	-	-	(25,101,974.66)
Gas Distribution...	(60,212,131.14)	(1,067,894.13)	-	-	-	-	1,210,181.42	-	-	(60,069,843.85)
Gas General Plant..	(0.02)	-	-	-	-	-	-	-	-	(0.02)
Gas Storage...	(170,437.90)	(46,318.74)	-	-	-	-	31,158.31	-	-	(185,598.33)
Gas Stored Nonrecoverable...	-	-	-	-	-	-	-	-	-	-
Gas Transmission..	(3,016,813.95)	(4,523.38)	-	-	-	-	32,210.90	-	-	(2,989,126.43)
Non Utility Property...	-	-	-	-	-	-	-	-	-	-
	$ (331,889,205.84)	$ (9,665,579.20)	$ -	$ -	$ -	$ -	$ 4,203,502.55	$ -	$ -	$ (337,351,282.49)

May 26, 2011

Louisville Gas and Electric 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
Salvage										
Common General Plant	$ 278,074.55	$ 127.76	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 278,202.31
Electric Distribution	17,535,024.98	458,878.23	-	-	-	-	-	(179,248.50)	-	17,814,654.71
Electric General Plant	138,281.25	770.20	-	-	-	-	-	-	-	139,051.45
Electric Hydro Production	376,638.17	-	-	-	-	-	-	-	-	376,638.17
Electric Other Production	(18,998.67)	-	-	-	-	-	-	-	-	(18,998.67)
Electric Steam Production	22,028,570.14	668,582.62	-	-	-	-	-	(11,318.62)	-	22,685,834.14
Electric Transmission	6,247,368.67	86,557.80	-	-	-	-	-	-	-	6,333,926.47
Gas Distribution	3,594,440.75	65,451.60	-	-	-	-	-	-	-	3,659,892.35
Gas General Plant	225,788.37	701.12	-	-	-	-	-	-	-	226,489.49
Gas Storage	269,933.04	5,653.13	-	-	-	-	-	-	-	275,586.17
Gas Stored Nonrecoverable	-	-	-	-	-	-	-	-	-	-
Gas Transmission	217,923.11	1,696.26	-	-	-	-	-	-	-	219,619.37
Non Utility Property	-	-	-	-	-	-	-	-	-	-
	50,893,044.36	1,288,418.72	-	-	-	-	-	(190,567.12)	-	51,990,895.96
Total Reserves										
Common	(77,737,236.57)	(4,238,129.46)	251,177.24	-	-	-	68,506.21	-	-	(81,655,682.58)
Electric	(1,730,321,891.37)	(36,637,129.90)	8,126,633.71	-	-	-	2,861,445.71	(190,567.12)	-	(1,756,161,508.97)
Gas	(231,266,492.01)	(5,565,936.23)	1,463,342.09	-	-	-	1,273,550.63	-	-	(234,095,535.52)
	(2,039,325,619.95)	(46,441,195.59)	9,841,153.04	-	-	-	4,203,502.55	(190,567.12)	-	(2,071,912,727.07)
Retirement Work In Progress										
Common	342,947.00	-	-	-	-	(68,506.21)	(18,252.23)	(17,894.00)	-	238,294.56
Electric	9,603,653.21	-	-	78,125.77	(83,329.50)	(2,587,549.09)	3,098,487.60	(130,869.17)	(32,678.11)	9,945,840.71
Gas	2,523,160.64	-	-	(78,125.77)	(283,217.01)	(990,333.62)	577,050.15	(3,332.90)	(2,374.27)	1,742,827.22
	12,469,760.85	-	-	-	(366,546.51)	(3,646,388.92)	3,657,285.52	(152,096.07)	(35,052.38)	11,926,962.49
YTD ACTIVITY	(2,026,855,859.10)	(46,441,195.59)	9,841,153.04	-	(366,546.51)	(3,646,388.92)	7,860,788.07	(342,663.19)	(35,052.38)	(2,059,985,764.58)
Amortization										
Common	(16,306,390.60)	(2,587,218.24)	826,740.33	-	-	-	-	-	-	(18,066,868.51)
Electric	(100.00)	-	-	-	-	-	-	-	-	(100.00)
Gas	(800.00)	-	-	-	-	-	-	-	-	(800.00)
AMORTIZATION TOTAL	(16,307,290.60)	(2,587,218.24)	826,740.33	-	-	-	-	-	-	(18,067,768.51)
Depreciation & Amortization Total	$ (2,043,163,149.70)	$ (49,028,413.83)	$ 10,667,893.37	$ -	$ (366,546.51)	$ (3,646,388.92)	$ 7,860,788.07	$ (342,663.19)	$ (35,052.38)	$ (2,078,053,533.09)
Depr & Amort - Nonutility for Balance Sheet										(2,077,990,172.73)
Utility Plant at Original Cost Less Reserve for Depreciation & Amortization (Excl nonutility)	$ 2,705,739,864.67									$ 2,704,887,905.82

May 26, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
April 30, 2011

	Current Month		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues...	$ 73,908,472.30	$ -	$ 73,908,472.30
Gas Operating Revenues...	18,642,881.93	-	18,642,881.93
Total Operating Revenues..	92,551,354.23	-	92,551,354.23
Fuel for Electric Generation..	26,601,752.01	-	26,601,752.01
Power Purchased..	4,930,724.70	-	4,930,724.70
Gas Supply Expenses...	8,665,043.42	-	8,665,043.42
Other Operation Expenses...	17,724,384.01	-	17,724,384.01
Maintenance..	11,168,994.71	-	11,168,994.71
Depreciation..	11,806,358.00	52.77	11,806,410.77
Amortization Expense...	657,834.15	-	657,834.15
Regulatory Credits...	(467,346.27)	-	(467,346.27)
Taxes			
Federal Income..	1,727,882.62	-	1,727,882.62
State Income..	315,115.37	-	315,115.37
Deferred Federal Income - Net...................................	-	8,213.43	8,213.43
Deferred State Income - Net.......................................	-	1,497.89	1,497.89
Property and Other..	2,272,396.13	-	2,272,396.13
Investment Tax Credit..	-	-	-
Amortization of Investment Tax Credit......................	(236,034.00)	-	(236,034.00)
Loss (Gain) from Disposition of Allowances................	-	-	-
Accretion Expense...	221,493.64	-	221,493.64
Total Operating Expenses...	85,388,598.49	9,764.09	85,398,362.58
Net Operating Income..	7,162,755.74	(9,764.09)	7,152,991.65
Other Income Less Deductions...................................	(961,726.27)	-	(961,726.27)
Income Before Interest Charges.................................	6,201,029.47	(9,764.09)	6,191,265.38
Interest on Long-Term Debt..	3,322,584.57	(25,017.63)	3,297,566.94
Amortization of Debt Expense - Net.............................	275,309.85	-	275,309.85
Other Interest Expenses..	119,638.44	-	119,638.44
Total Interest Charges...	3,717,532.86	(25,017.63)	3,692,515.23
Net Income..	$ 2,483,496.61	$ 15,253.54	$ 2,498,750.15

Note: Purchase accounting is subject to change through October 31, 2011

May 26, 2011

Louisville Gas and Electric Company
Statement of Income with Purchase Accounting
April 30, 2011

	Year to Date		
	Without Purchase Accounting	Purchase Accounting	Total
Electric Operating Revenues.......................................	$ 330,174,976.62	$ -	$ 330,174,976.62
Gas Operating Revenues...	156,085,235.55	-	156,085,235.55
Total Operating Revenues..	486,260,212.17	-	486,260,212.17
Fuel for Electric Generation..	114,871,573.96	-	114,871,573.96
Power Purchased...	24,542,025.76	-	24,542,025.76
Gas Supply Expenses..	92,293,389.66	-	92,293,389.66
Other Operation Expenses...	76,454,657.54	27,884.66	76,482,542.20
Maintenance..	38,829,083.89	-	38,829,083.89
Depreciation..	46,336,399.35	(6.11)	46,336,393.24
Amortization Expense...	2,587,218.24	-	2,587,218.24
Regulatory Credits...	(1,569,955.95)	-	(1,569,955.95)
Taxes			
Federal Income...	7,740,019.30	-	7,740,019.30
State Income..	3,469,386.01	-	3,469,386.01
Deferred Federal Income - Net.................................	13,658,485.33	23,751.15	13,682,236.48
Deferred State Income - Net.....................................	341,927.36	4,331.52	346,258.88
Property and Other...	9,199,838.86	-	9,199,838.86
Investment Tax Credit..	-	-	-
Amortization of Investment Tax Credit....................	(917,469.00)	-	(917,469.00)
Loss (Gain) from Disposition of Allowances...............	(2,577.94)	-	(2,577.94)
Accretion Expense..	880,304.24	-	880,304.24
Total Operating Expenses..	428,714,306.61	55,961.22	428,770,267.83
Net Operating Income...	57,545,905.56	(55,961.22)	57,489,944.34
Other Income Less Deductions.................................	(1,148,540.20)	-	(1,148,540.20)
Income Before Interest Charges................................	56,397,365.36	(55,961.22)	56,341,404.14
Interest on Long-Term Debt..	13,139,209.97	(100,070.52)	13,039,139.45
Amortization of Debt Expense - Net...........................	1,098,639.22	-	1,098,639.22
Other Interest Expenses...	580,571.77	-	580,571.77
Total Interest Charges..	14,818,420.96	(100,070.52)	14,718,350.44
Net Income..	$ 41,578,944.40	$ 44,109.30	$ 41,623,053.70

Note: Purchase accounting is subject to change through October 31, 2011

May 26, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
April 30, 2011

	Current Month without Purchase Accounting		Current Month Purchase Accounting		Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period……………………………	$ 849,838,699.75	$ 757,728,567.29	$ (808,870,426.68)	$ -	$ 40,968,273.07	$ 757,728,567.29
Add:						
Net Income (Loss) for Period…………………………	2,483,496.61	(601,505.30)	15,253.54	-	2,498,750.15	(601,505.30)
Deduct:						
Adjustment to Retained Earnings……………………	-	-	-	-	-	-
Common Dividends						
Common Stock Without Par Value………………	-	-	-	-	-	-
Balance at End of Period…………………………………	$ 852,322,196.36	$ 757,127,061.99	$ (808,855,173.14)	$ -	$ 43,467,023.22	$ 757,127,061.99

Note: Purchase accounting is subject to change through October 31, 2011

May 26, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
April 30, 2011

	Year to Date without Purchase Accounting		Year to Date Purchase Accounting		Year to Date Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period................................	$ 827,993,251.96	$ 755,278,866.24	$ (808,899,282.44)	$ -	$ 19,093,969.52	$ 755,278,866.24
Add:						
Net Income (Loss) for Period.............................	41,578,944.40	31,848,195.75	44,109.30	-	41,623,053.70	31,848,195.75
Deduct:						
Adjustment to Retained Earnings........................	-	-		-	-	-
Common Dividends						
Common Stock Without Par Value.................	17,250,000.00	30,000,000.00	-	-	17,250,000.00	30,000,000.00
Balance at End of Period.......................................	$ 852,322,196.36	$ 757,127,061.99	$ (808,855,173.14)	$ -	$ 43,467,023.22	$ 757,127,061.99

Note: Purchase accounting is subject to change through October 31, 2011

May 26, 2011

Louisville Gas and Electric Company
Analysis of Retained Earnings with Purchase Accounting
April 30, 2011

	Year Ended Current Month without Purchase Accounting		Year Ended Current Month to Date Purchase Accounting		Year Ended Current Month Combined	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Balance at Beginning of Period…………………………….	$ 757,127,061.99	$ 713,253,867.26	$ -	$ -	$ 757,127,061.99	$ 713,253,867.26
Add:						
Net Income (Loss) for Period…………………………	137,445,134.37	118,873,194.73	91,718.38	-	137,536,852.75	118,873,194.73
Deduct:						
Adjustment to Retained Earnings……………………	-	-	808,946,891.52	-	808,946,891.52	-
Common Dividends						
Common Stock Without Par Value………………	42,250,000.00	75,000,000.00	-	-	42,250,000.00	75,000,000.00
Balance at End of Period…………………………………	$ 852,322,196.36	$ 757,127,061.99	$ (808,855,173.14)	$ -	$ 43,467,023.22	$ 757,127,061.99

Note: Purchase accounting is subject to change through October 31, 2011

May 26, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of April 30, 2011

Assets	Without Purchase Accounting	Purchase Accounting	Total
Utility Plant			
Utility Plant at Original Cost....................................	$ 4,782,878,078.55	$ (1,751,237,445.63)	$ 3,031,640,632.92
Less Reserves for Depreciation and Amortization.....	2,077,990,172.73	(1,751,237,451.74)	326,752,720.99
Total..	2,704,887,905.82	6.11	2,704,887,911.93
Investments			
Ohio Valley Electric Corporation.............................	594,286.00	-	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	-	11,879.20
Special Funds...	20,392,613.99	-	20,392,613.99
Total..	20,998,779.19	-	20,998,779.19
Current and Accrued Assets			
Cash..	32,004,651.77	-	32,004,651.77
Special Deposits...	5,336,432.10	-	5,336,432.10
Temporary Cash Investments...................................	32,004,573.78	-	32,004,573.78
Accounts Receivable - Less Reserve.........................	116,387,007.31	-	116,387,007.31
Accounts Receivable from Associated Companies....	11,414,595.15	-	11,414,595.15
Materials and Supplies - At Average Cost................			
Fuel..	64,634,046.64	-	64,634,046.64
Plant Materials and Operating Supplies.................	29,834,678.95	-	29,834,678.95
Stores Expense...	5,079,805.34	-	5,079,805.34
Gas Stored Underground.......................................	14,392,608.85	-	14,392,608.85
Emission Allowances...	2,409.88	-	2,409.88
Prepayments..	7,049,940.71	-	7,049,940.71
Miscellaneous Current and Accrued Assets..............	724,075.07	-	724,075.07
Total..	318,864,825.55	-	318,864,825.55
Deferred Debits and Other			
Unamortized Debt Expense......................................	13,309,465.49	(3,605,555.13)	9,703,910.36
Unamortized Loss on Bonds....................................	21,530,637.65	-	21,530,637.65
Accumulated Deferred Income Taxes.......................	53,426,611.12	83,151,053.04	136,577,664.16
Deferred Regulatory Assets.....................................	361,306,009.06	12,103,999.24	373,410,008.30
Other Deferred Debits..	1,251,973.01	194,232,040.91	195,484,013.92
Goodwill..	-	389,157,351.59	389,157,351.59
Total..	450,824,696.33	675,038,889.65	1,125,863,585.98
Total Assets..	$ 3,495,576,206.89	$ 675,038,895.76	$ 4,170,615,102.65

Note: Purchase accounting is subject to change through October 31, 2011

May 26, 2011

Louisville Gas and Electric Company
Balance Sheet with Purchase Accounting Adjustments
As of April 30, 2011

Liabilities and Proprietary Capital	Without Purchase Accounting	Purchase Accounting	Total
Proprietary Capital			
Common Stock...	$ 425,170,424.09	$ -	$ 425,170,424.09
Less: Common Stock Expense......................................	835,888.64	-	835,888.64
Paid-In Capital..	83,581,499.00	1,194,085,869.02	1,277,667,368.02
Other Comprehensive Income......................................	-	-	-
Retained Earnings..	852,322,196.36	(808,855,173.14)	43,467,023.22
Total Proprietary Capital...	1,360,238,230.81	385,230,695.88	1,745,468,926.69
Pollution Control Bonds - Net of Reacquired Bonds....	574,304,000.00	6,426,611.22	580,730,611.22
First Mortgage Bonds..	531,144,969.14	-	531,144,969.14
LT Notes Payable to Associated Companies................	-	-	-
Total Long-Term Debt..	1,105,448,969.14	6,426,611.22	1,111,875,580.36
Total Capitalization..	2,465,687,199.95	391,657,307.10	2,857,344,507.05
Current and Accrued Liabilities			
ST Notes Payable to Associated Companies................	-	-	-
Accounts Payable..	72,770,225.00	-	72,770,225.00
Accounts Payable to Associated Companies................	27,020,672.69	-	27,020,672.69
Customer Deposits..	23,394,006.56	-	23,394,006.56
Taxes Accrued..	7,782,784.18	-	7,782,784.18
Dividends Declared..	-	-	-
Interest Accrued..	13,874,035.61	-	13,874,035.61
Miscellaneous Current and Accrued Liabilities...........	29,874,305.15	-	29,874,305.15
Total..	174,716,029.19	-	174,716,029.19
Deferred Credits and Other			
Accumulated Deferred Income Taxes..........................	487,780,888.27	80,651,103.64	568,431,991.91
Investment Tax Credit..	44,607,107.13	-	44,607,107.13
Regulatory Liabilities...	61,508,554.02	194,232,040.91	255,740,594.93
Customer Advances for Construction...........................	8,115,146.29	-	8,115,146.29
Asset Retirement Obligations.......................................	53,172,083.34	-	53,172,083.34
Other Deferred Credits...	15,198,179.97	8,498,444.11	23,696,624.08
Miscellaneous Long-Term Liabilities...........................	36,567,706.97	-	36,567,706.97
Misc Long-Term Liab Due to Assoc Cos......................	-	-	-
Accum Provision for Postretirement Benefits..............	148,223,311.76	-	148,223,311.76
Total..	855,172,977.75	283,381,588.66	1,138,554,566.41
Total Liabilities and Stockholders' Equity.........................	$ 3,495,576,206.89	$ 675,038,895.76	$ 4,170,615,102.65

Note: Purchase accounting is subject to change through October 31, 2011

May 26, 2011